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JOINT BIDDING FOR FEDERAL ONSHORE OIL AND GAS LANDS, AND COAL AND OIL SHALE LANDS

PRINTED AT THE REQUEST OF

HENRY M. JACKSON, Chairman

COMMITTEE ON INTERIOR AND INSULAR AFFAIRS

UNITED STATES SENATE

PURSUANT TO

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A NATIONAL FUELS AND ENERGY POLICY STUDY

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SENATE RESOLUTION 45

National Fuels and Energy Policy Study

This publication is printed for the use of Senators participating in the National Fuels and Energy Policy Study, authorized by Senate Resolution 45 of the 92d Congress.

Senate Resolution 45, introduced by Senators Jennings Randolph and Henry M. Jackson, was amended and agreed to by the Senate on May 3, 1971. The resolution authorized the Senate Committee on Interior and Insular Affairs and ex officio members of the Committees on Commerce and Public Works and the Joint Committee on Atomic Energy to make a comprehensive study of programs and policies required to meet national energy needs.

Subsequently, the Senate approved the addition of ex officio members from the Committees on Aeronautical and Space Sciences, on Finance, on Foreign Relations, on Government Operations, and on Labor and Public Welfare.

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MEMORANDUM OF THE CHAIRMAN

To Members and Ex Officio Members of the National Fuels and Energy Policy Study (S. Res. 45, 92d Congress), Committee on Interior and Insular Affairs:

Section 105 of the Energy Policy and Conservation Act (Public Law 94–163) directed the Secretary of the Interior to adopt a rule prohibiting participation by more than one "major oil company" in a joint bid for oil and gas leases on the Outer Continental Shelf, subject to certain exceptions.

Section 105(e) of the Act provided—

"(e) The Secretary shall study and report to the Congress, not later than six months after the date of enactment of this Act, with respect to the feasibility and desirability of extending the prohibition on joint bidding to—

> "(1) bidding for any right to develop crude oil, natural gas, and natural gas liquids on Federal lands other than those located on the Outer Continental Shelf; and
>
> "(2) bidding for any right to develop coal and oil shale on such lands."

On June 29, the Secretary transmitted this study to me. I have directed that it be published as a committee print for the information of committee members and other interested parties.

Henry M. Jackson, *Chairman.*

LETTER OF TRANSMITTAL

U.S. DEPARTMENT OF THE INTERIOR,
OFFICE OF THE SECRETARY,
Washington, D.C., June 29, 1976.

Hon. HENRY M. JACKSON,
Chairman, Senate Interior Committee,
Washington, D.C.

DEAR MR. CHAIRMAN: Section 105(e) of Public Law 94–163, the Energy Policy and Conservation Act, requires me to report to the Congress with respect to the feasibility and desirability of extending to onshore Federal energy leases the prohibition which now exists on joint bidding for Outer Continental Shelf oil and gas leases. I am happy to enclose the required report.

The recommendations of the report are that a joint-bidding ban be extended to oil and gas onshore, and to coal, but that no action be taken at this time as to oil shale, since no general leasing program for oil shale is now under way. It is our feeling that although little or no joint bidding has actually occurred in the past for onshore oil and gas or for coal, on balance the advantages of a limited ban seem to outweigh the disadvantages in these energy materials. We see no need to decide the issue for oil shale until general leasing is planned, at which time further experience with oil shale development may enable us to make a better-informed decision.

As you know, a ban on Outer Continental Shelf joint bidding was originated by the Department of the Interior and was in effect before the Energy Policy and Conservation Act was passed in December 1975. That Act legislated essentially the same ban as had previously been in our regulations. We have authority under the Mineral Leasing Act to promulgate onshore joint-bidding limitations as well, either by regulation or by announcement of qualifications for bidding. It is my view that legislation on this matter is unnecessary and undesirable, since a legislated ban is far too inflexible to suit the continually changing circumstances of the market for Federal energy leases. Rapid world energy price changes, differences in exploration risk among regions and even among individual leases in the same region, changing company structures and investment policies, and many other factors make it essential that joint-bidding limitations be easily and quickly adjusted, as they can be only if they are regulatory in character.

Therefore, while it is my intention to limit joint bidding along the general lines suggested in this study, I do not recommend legislation on the matter. Further, I believe that more study is necessary of certain issues not yet adequately addressed. The exact size limits to be placed on eligibility for joint-bidding in coal are not well substantiated and need further work. No mention is made in this study

of the criteria by which waivers to a ban should be granted when risks are unusually high because of large exploration costs, great exploration uncertainty, high technology, or any of a number of other possibilities for which allowance should be made. I am directing my staff to provide me with recommendations on these matters before I decide on the final promulgation of joint-bidding limitations.

Sincerely,

THOMAS S. KLEPPE,
Secretary of the Interior.

Enclosure.

JOINT BIDDING FOR FEDERAL ONSHORE OIL AND GAS LANDS,

AND COAL AND OIL SHALE LANDS

(A study required by Section 105(e) of P.L. 94-163, the Energy Policy and Conservation Act of 1975)

Department of the Interior
Office of Policy Analysis
June 1976

1. INTRODUCTION AND SUMMARY

In the Energy Policy and Conservation Act of 1975[1/], the Congress instructed the Secretary of the Interior to prescribe and make effective a rule which prohibits participation by more than one of the "major" oil companies in a joint bid for the oil and gas rights on any lands located on the Outer Continental Shelf (OCS), except where extremely high risk exists or where high exploration and development costs are involved. The Secretary was also instructed to study and report on the feasibility and desirability of extending this prohibition on joint bidding to the sales of oil and gas rights on Federal onshore lands, and to the sales of coal and oil shale rights on such lands.

The report that follows studies these questions. In Section 2 the theory of joint bidding is outlined briefly. Here we examine the risk-sharing features of joint bidding in ventures whose outcomes are uncertain, and the consequent encouragement offered to smaller, more risk-averse firms to enter the bidding competition. But joint bidding has an opposite effect as well: a joint bid consolidates many offers into one, and converts what might have been active competition into legitimate collusion. We note some of the other features of joint bidding that bear on competition -- such as the opportunity that joint bidding negotiations may provide to exchange information about potential bids and geological data.

1/ 42 USC 6201; Public Law 94-163, 94th Congress, S. 622, Dec. 22, 1975. (See Appendix B where the relevant Sections 103(a-e) are reproduced).

We conclude that joint bidding is likely, on balance, to encourage competition if risks are large, and to discourage competition if risks are low.

In Section 3 we review the history of OCS bidding since its start in 1954, and we summarize some of the discussions and analyses of that history leading up to the 1975 restrictions on OCS joint bidding. This history is most useful as a benchmark against which to compare the situations in the current onshore oil and gas bidding, and the soon-to-be-active bidding for Federal coal and oil shale lands.

In Section 4 the characteristics of the bidding for competitively offered Federal onshore oil and gas lands are examined. Attention is focused on the levels of aggregate activity and on the investments, the costs, and the risks involved in onshore oil and gas ventures, especially as they compare to their counterparts in OCS ventures.

In Section 5 the prospects for competition in the sales of coal are examined. The structure of the industry -- which includes many firms not ordinarily considered coal mining firms -- is described, and the expected influence on that industry's behavior of the complicated patterns of western land ownership are analyzed.

We conclude that there is little justification for joint bidding for competitively leased Federal onshore oil and gas tracts. Although the probability is high that any such venture will not discover oil or gas, the magnitude of the typical operation in terms of the investment at

stake is so small that no pooling of risk is required to encourage competition. So long, then, as joint bidding is freely permitted there exists the potential that industry may use this device to obtain Federal leases at less than their true market value.

We recommend, then, that the restriction on joint bidding, exactly as stated in Section 105(a-d) of the Energy Policy and Conservation Act of 1975 (42 USC 6213), should be extended to cover the bidding for any right to develop crude oil, natural gas, and natural gas liquids on Federal lands other than those located on the Outer Continental Shelf.

We judge that the competition that can be expected in the bidding for western Federal coal lands is too fragile to allow the further dilution that unrestricted joint bidding would bring. We do not find the risks involved in undertaking the initial development of a coal tract to be of a large enough magnitude to justify unrestricted joint bidding. We conclude that a restriction on joint bidding, similar to that contained in Section 105 of the Energy Policy and Conservation Act of 1975 (42 USC 6213) should be extended to cover the bidding for any right to develop coal on Federal lands. We recommend, further, that the firms which are to be restricted from bidding with each other in joint coal ventures shall be those firms producing more than 25 million tons of coal annually.

In Section 6 the recent beginnings of a prototype shale oil industry on Federal lands are reviewed. Here technological uncertainties dominate

the picture. Experience is too limited to predict the future or, indeed, even the existence of this new industry with any assurance. One set of lease sales has taken place; more sales await the experiences gained in the early developmental stages of the four tracts already leased. The risk involved in a shale oil venture is high and might therefore appear to justify allowing joint bidding to make entry into competition more attractive. But the risk seems to be more at the development stage of the venture -- like some of the more advanced coal conversion proposals -- than at the discovery stage -- like OCS oil. There is the possibility, then, that means other than joint bidding can be found which will enable bidders to share these risks with other firms. Since new leasing in any quantity is, in any event, to be postponed until more developmental experience is gained on the four tracts already leased, it is appropriate to defer any action on a joint bidding restriction as well.

We recommend, then, that the decision on whether to restrict joint bidding for Federal oil shale lands be postponed to that time -- possibly three or four years hence -- when sufficient evidence on development and production experience shall have accumulated to warrant the resumption of leasing. At that time it will be more nearly feasible to assess the incidence of risk on the winner of an oil shale lease.

2. JOINT BIDDING, RISKS, AND COMPETITION

We are accustomed to the long-established regulatory philosophy which looks with disfavor on cooperative price setting by otherwise competitive firms. The economic argument underlying this philosophy points to two consequences of such behavior: buyers of the product are forced to pay a higher price, and (generally) less of the product is produced and consumed. The price-fixing has made the buyers worse off and the sellers better off. The argument against joint price fixing by otherwise competitive buyers is exactly analogous. Other things being equal, the more that the Federal Government obtains for its lands, the better. Therefore, if the pie is large enough, and if "other things" can be maintained equal, bidding practices which drive down tract prices should be prohibited.

But the foregoing argument has ignored a feature important in the marketing of many Federal mineral-rights leases: risk and uncertainty. If there is large uncertainty as to what resources exploration will reveal, the risk involved in buying a lease may represent a prospect of ruin for all but the largest and most secure of firms. Indeed, in the case of OCS, even the "majors" may find some of the risks unacceptable. With even the keenest competition in bidding, the government may find that the price it receives for a risky tract of land is substantially below the average of the excess profits that the winning firm can expect to derive from its undertaking. To be specific, suppose that $10 million worth of oil is in prospect on a particular tract, with one chance in 10 of its being there. Assume that exploration costs are $200,000. The average expectation of the gross profit before deducting the cost of the lease

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is $800,000 (one-tenth of $10 million, less $200,000). The firm with too small a land or investment protfolio to average out this unlucky loss with other lucky gains will offer less than $800,000 for this tract. A larger firm with 20 other investments like this one can offer up to $800,000 with assurance that, short of highly improbable misfortune, something near to the mathematical average of his 20 projects will be realized.

To capture in the price of a lease the full value of the average excess profits to be had in a large and risky tract, the government must either shoulder the risk itself, or devise and/or encourage some scheme by which firms may pool their risky investments so as to jointly self-insure against catastrophic losses. Without some such scheme, the competition for the riskiest tracts will be limited to the very largest firms. And competition among fewer firms will usually mean lower bids. By "high risk," here, we mean a low probability of a substantial find <u>together with</u> a sizable investment at risk.

Joint bidding is one such risk-pooling scheme. In a joint bid evenly shared between two firms the risk probability that a single firm faces on that tract is the same, but the investment at risk has been halved. The same initial resources will allow this firm to participate in <u>two</u> such joint bidding ventures. To this firm the <u>average</u> outcome of this diversified portfolio is the same as in the single venture, but the <u>dispersion</u> of outcomes is much narrower. High gains and high losses are less likely; the result is more likely to be near the mathematical average. This

statistical phenomenon is familiar in the case of flips of a coin: for one flip, the probability of no heads appearing is one in two, but for two flips, the probability of no heads is only one in four, and for three flips, one in eight. Thus, by dividing its investment among several prospects through joint bidding, a firm can reduce the chance of a catastrophic loss.

It is important in considering a ban on joint bidding to distinguish between risks which are closely associated with the actual bidding for a lease, and risks which are associated with later development activity. Only the bidding risk is relevant to a joint-bidding ban, because the development risk can be pooled, after a lease has been purchased, by the assignment of all or part of one's interest to other parties. In the case of an oil and gas lease, for example, the main element of <u>bidding</u> risk is that associated with uncertainty about the presence of oil or gas; exploration will resolve this uncertainty shortly after the lease sale, and the winning bidder or bidders for the lease must bear the risk of the outcome. On the other hand, risks such as those associated with long-run oil price fluctuations, or future changes in the technology and cost of oil and gas extraction, have little relevance to the question of joint bidding since a lessee's ability to diversify against these risks is not significantly affected by the existence of a joint bidding ban. Such a ban, in itself, prohibits only joint bidding, not joint development, and development risks are therefore not an important factor in whether joint bidding should be banned.

The overall influence of joint bidding on the intensity of competition is not easy to determine because there are two opposing effects. Two firms which join together in a bid submit one offer in place of two, and competition is thereby reduced. But the joint bidder, with his less risky land portfolio, will find it more attractive to bid in more contests. The sum of these two effects is not clear. Generally, however, we might expect that where risk is extremely high, risk reduction through joint bidding will probably encourage participation in sufficiently many more contests to offset the reduction brought about by the joining together of bids. Where risk is relatively low, we would expect the reverse: that little new participation is encouraged, and that many multiple-bid contests become few-bid contests.

It has been suggested that the negotiations involved in putting together a joint bid may serve as a vehicle for purposes not directly connected with the joint bid; indeed, that consideration of these other purposes may be more important for the evaluation of competition than the joint bidding itself. In her recent study[2/] of joint bidding in OCS, Wilcox has stated that:

> "Consideration of possible anti-competitive effects of joint ventures should be made since structural conditions accommodating mutually advantageous behavior may be provided through joint operations. Proximity of firms in joint ventures would facilitate cooperation in oil production and other activities. The joint venture arrangement could provide a medium to distribute gains,

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2/ Wilcox, Susan Margaret, Joint Venture Bidding and Entry in the Market for Offshore Petroleum Leases, Doctoral dissertation, University of California, Santa Barbara (March 1975).

> develop policies and enforce collusive agreements since financial transactions and mutual coordination are established in the joint activities. The joint venture structure may also allow firms to influence member firms in activities unrelated to the purpose of the joint venture." 3/

In another recent study4/ Gaskins and Vann have argued that in the process of negotiating an OCS joint bid on one tract, major firm participants exchange information concerning the identity of other tracts on which they intend to bid. Such information makes them better informed than some other competitors are about the likely numbers of active bidders who will compete in various auctions. Knowing that number is useful, for the greater the number of bidders in a contest, the higher a bid must be to have a given chance of winning. (This simple statistical fact is borne out by the data in both onshore and offshore oil and gas sales; see Sections 3 and 4 below, where some of this evidence is presented). The better informed firm can choose contests where it knows the competition is going to be slim, and it can win in these contests with lower bids. The net effect of this information exchange is that competition is reduced and government revenues are diminished.

3/ Ibid. pp. 41-42

4/ Gaskins, Darius and Barry Vann, "Joint Buying and the Seller's Return - the Case of OCS Lease Sales" (1975).

3. THE CASE FOR A JOINT BIDDING BAN IN OCS--REVIEWED

Since 1954, when leasing of oil and gas rights on Federal lands on the Outer Continental Shelf began, 38 competitive sales have (through 1975) been conducted by the Bureau of Land Management. A total of 2,705 tracts have been leased for bonus payments totalling $15,917 million. Sales have been held in the Gulf of Mexico, the West Coast and Alaska. The average tract has been 4,645 acres in size, has received 3.66 bids, and has brought a high bid of $5.88 million.[5/]

Through time, the trends as shown in Figures 1 and 2 have been strongly upward in both size of tracts and bonus price per acre, so that entry into these contests requires substantial capital. Total annual government revenue from selling OCS leases reached nearly $7 billion in 1974; individual transactions have exceed $200 million, and tracts selling for as much as $50 million are not uncommon.

There are two kinds of Federal offshore lease sales: drainage sales and general sales. Drainage sales are those in which the tracts offered are ones subject to depletion of their oil and gas deposits from wells on adjacent tracts. The U. S. Geological Survey identifies tracts subject to drainage for these sales. General sales offer a mixture of drainage tracts, tracts in moderately developed areas, and rank wildcat tracts which are generally located 5 or more miles from tracts with established production.

5/ These numbers quoted are from BLM's Outer Continental Shelf Statistical Summary, 1954-1974 and subsequent periodic updatings of that publication. The averages given include data through CY 1975; this is up to and including Sale #38a.

The BLM now formulates a tentative 5-year OCS leasing schedule. During the development and updating of the tentative OCS leasing schedule, general sale areas are identified. In the specific tract selection process, BLM and U.S. Geological Survey (USGS) gather and review more detailed geologic, engineering, economic, and environmental information on areas proposed for sale. Nominations of tracts that the oil and gas industry would like to see offered in a specific sale are carefully considered in the tract selection process.

After tracts have been selected for study for a specific sale, a draft environmental statement is prepared by BLM. These statements, required by the National Environmental Policy Act of 1969 (P.L. 91-190), present detailed environmental analysis of the proposed sale. Public hearings are conducted where all interested parties may speak and the final environmental impact statement is prepared considering public hearing testimony and written comments received on the draft statement. At any time during this process, tracts may be deleted from the proposed sale because of environmental reasons.

The date of the sale is announced in the Federal Register and on that date sealed bids are accepted. Leases are issued for each tract to the highest responsible qualified bidder complying with all regulations. High bids may be rejected if it is determined that they do not represent fair market value. As the stakes in these lease auctions grow more and more enormous, there has been increasing concern over whether the government is receiving true value for the lands being leased.

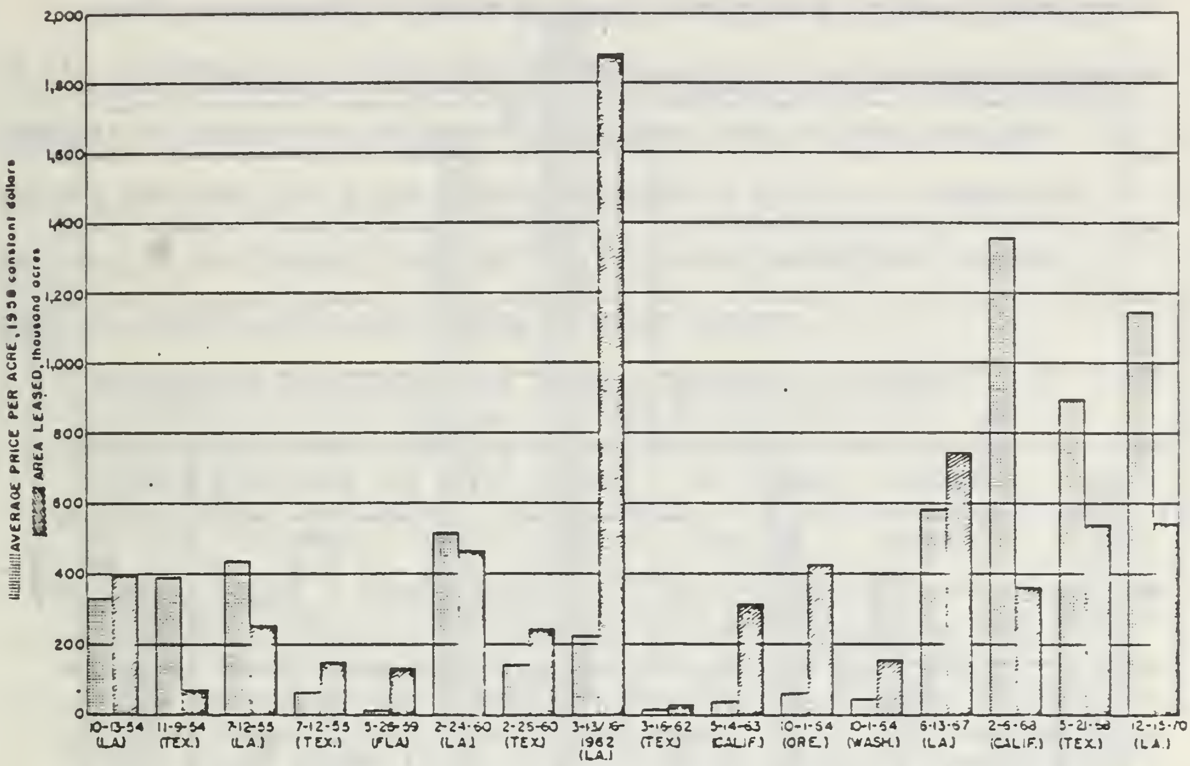

FIGURE 1. - Average Price Paid per Acre and Acreage Leased, Federal Offshore General Sales, 1954-70.

Source: L. K. Weaver, C. J. Jirik, and H. F. Pierce, Offshore Petroleum Studies: Historical and Estimated Future Hydrocarbon Production from U.S. Offshore Areas and the Impact on the Onshore Segment of the Petroleum Industry, Information Circular 8575, Bureau of Mines (1973) pp. 6,8.

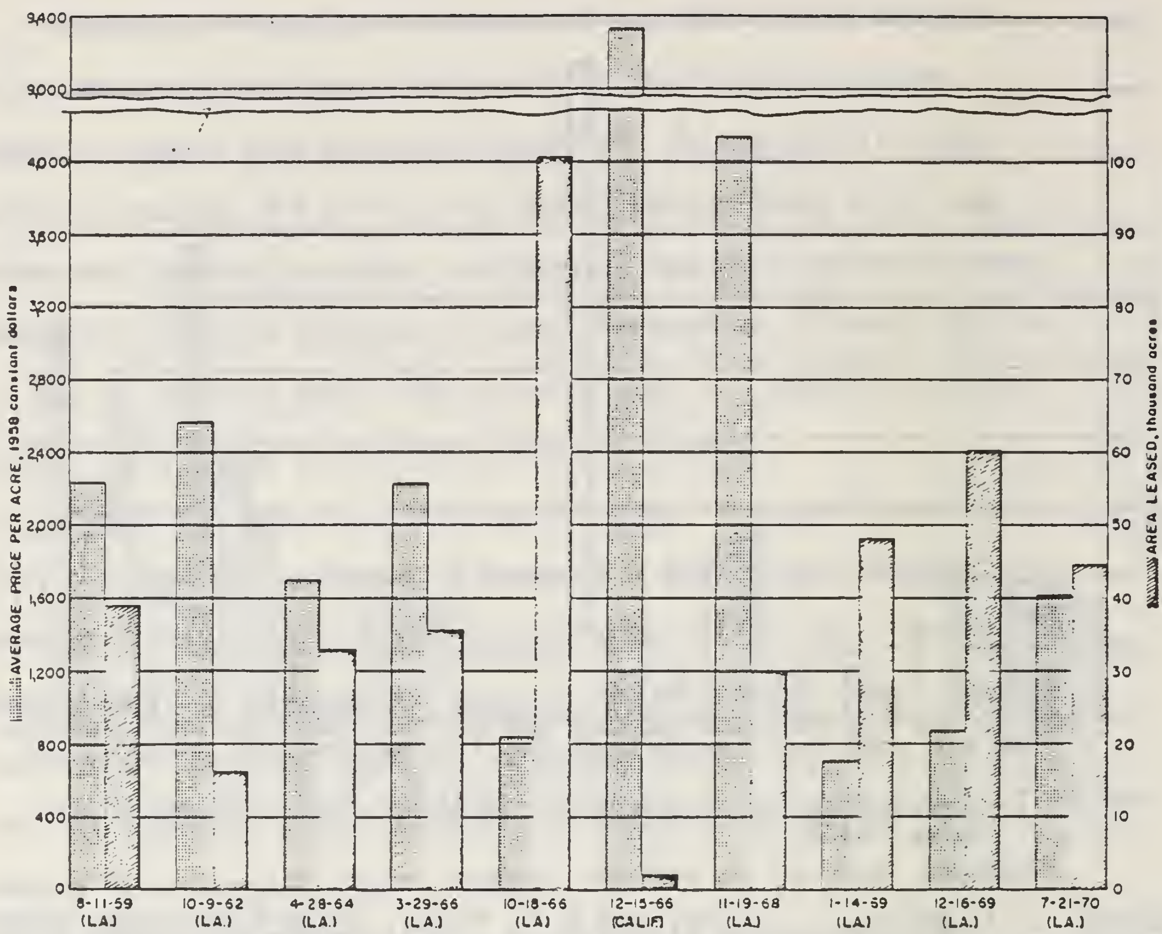

FIGURE 2 - Average Price Paid per Acre and Acreage Leased, Federal Offshore Drainage Sales, 1959-70.

Source: L. K. Weaver, C. J. Jirik, and H. F. Pierce, Offshore Petroleum Studies: Historical and Estimated Future Hydrocarbon Production from U.S. Offshore Areas and the Impact on the Onshore Segment of the Petroleum Industry, Information Circular 8575, Bureau of Mines (1973) pp. 6,8.

Looking at changes in bonus payments through the sixties, Weaver, et al, expressed the opinion that "Bidding appears to have become more competitive because the amount of lease bonus paid in 1958 constant dollars per acre during the 1966-71 interval is about four times that paid during the 1960-65 interval."[6/] They go on to explain, however, that the comparison is complicated by other factors:

> "An analysis of related data helps to explain the reason for different bid prices for the 1960-65 period. The comparatively large offering in the March 1962 sales offshore Louisiana and Texas probably led to less thorough overall tract evaluation. Consequently, bids were cautious and low. This large number of acres leased at an overall low average price per acre significantly affected the period averages. Also, relatively large amounts of acreage were offered in either rank wildcat or otherwise unproven areas offshore California, Oregon, and Washington in the 1960-65 period. (About 894,000 acres were leased in these areas at less than $50 per acre).[7/]

Walter Mead, writing in 1969, carried out the first extensive examination[8/] of the effectiveness of competition as a means of price determination for OCS tracts. He looked at evidence in the form of (1) the number of competitors for leases, (2) the practice of joint bidding, (3) the behavior of prices, (4) the inter-relationships of a number of variables affecting the price of leases, and (5) finally, the rate of return on the bonus investment.

6/ L. K. Weaver, C. J. Jirik, and H. F. Pierce, Offshore Petroleum Studies: Historical and Estimated Future Hydrocarbon Production from U. S. Offshore Areas and the Impact on the Onshore Segment of the Petroleum Industry, Information Circular 8575, Bureau of Mines (1973) pp. 6, 8.

7/ Ibid.

8/ Ch. 8 in Nossaman, Waters, Scott, Krueger, and Riordan, Study of Outer Continental Shelf Lands of the United States, U.S. Public Land Law Review Commission (1969).

In an analysis which examined (1) the size of the high-bidder firm; (2) the total value of all oil and gas production for the period 1954 through 1967 from the leases in question; (3) the corporate structure of the high-bidder, whether a single bidder or a combine; (4) number of acres in the tract; (5) number of bids received per tract; and (6) estimated water depth over the tract, he found that the number of bidders submitting bids for a tract was the most important determinant of the high-bid amount--the greater the number of bidders, the higher the high bid. Looking at the scatters of bids in the various sales he found that:

> "The statistics clearly reflect wide variations in the values which bidders place on property as a result of pre-bidding exploration which indicates the relatively subjective nature of the evaluation process and imprecise nature of such exploration. In addition, some of the considerable differences between high and low or second bids may be because the latter were put in as "fishing bids"--minimal offers reflecting a willingness of a bidder to take the property as a speculation at a token price. The relatively non-competitive sales, involving either one or two bidders, may consist largely of such bids.9/
>
> "One-bidder sales yielded a nominal price. The high-bids increase sharply with the number of bids, and where competition is effective, the high-bid averages 10.74 times the low-bid.10/
>
> "Where two or more bids are submitted for the same lease, the spread between the high and low-bids tends to be large and becomes very large as the number of bidders increases. This fact confirms the high degree of uncertainty about the true value of the property and indicates that competition is unreliable when bidders are few in number."11/

9/ Ibid., p. 496

10/ Ibid., p. 498

11/ Ibid., p. 503

Mead's work drew attention to joint bidding and its effects on this important number of bidders. Did joint bidding increase the numbers of bidders in these contests by the reduction in risk that is provided? Or, did it decrease the numbers of bidders by merely consolidating what might have been competing bids into single offers? He noted in the 1968 California sale that three large firms, in bidding jointly with each other, won 49 out of the 71 leases issued! In that same sale, all but one of the tracts were leased to a joint bid from one or another of some five bidding combines. He concludes, with regard to this sale, that "instead of 27 independent bidding units there are, in fact, six. They consist of one single bidder firm, Shell Oil Co., plus five combines. These five combines are composed of various groupings of 24 firms."[12/]

After drawing attention to the potential importance of joint bidding to the maintenance of competition, Mead only concluded that:

> "The evidence of joint bidding among competitors for oil and gas resources indicates that the number of independent bidding units is very small and considerably less than the number of firms in any bidding competition. The practice of joint bidding in the submerged areas is widespread. In the last analysis the need for combinations to share the risk should be weighed in terms of the competitive cost--a reduction in the number of independent bidding units to a relatively low level. On the other hand, when small firms that are individually unable to effectively compete for leases combine to submit a joint bid, it is apparent that the number of independent bidding units is increased."[13/]

12/ Ibid., p. 508

13/ Ibid., p. 513

Over time, the percentage of OCS bids which are joint bids has been gradually increasing. In the typical sale held after 1971, more than half the bids submitted were jointly formed, and most of the winning bids were joint bids. A tabulation of these percentages for the 38 sales up through CY 1975 is presented in Table 3.1. The trend can be seen in Figure 3 where this same information is presented graphically.

In a 1975 study, Wilcox made use of more recent OCS data in an attempt to test some of the questions about joint bidding that had been raised by Mead. She found that -- as would be expected in very risky ventures -- the practice of joint bidding significantly <u>increased</u> competition through encouraging entry.

> "In the 20 year period from 1954 to 1973, the number of firms acquiring OCS leases grew from 22 in the first lease sale to a total of 128 firms participating in OCS leasing. The eight major firms were among those initially winning OCS tracts. The number of entrants in 32 OCS lease sales since the first OCS sale is 106. Entry by firms into OCS leasing has been greater than the loss of firms through merger and acquisition. Of the initial 22 firms, 7 are now associated through merger with other firms. Most of the initial 22 firms were still successful bidders in 1973 OCS sales. Of all 128 firms participating in OCS leasing, 18 have since become interrelated with other firms through merger or acquisition. The number of firms active in the offshore petroleum market has increased 550 percent from the first OCS lease sale.
>
> "The joint bidding structure has been utilized as a means of entry enabling many firms to win OCS tracts which might not have been successful if joint bidding were not allowed. In support of the hypothesis that joint bidding facilitates entry, it was found that when entry occurred for the 106 firms, 87 (82 percent of the entering firms) bid jointly on every tract won in their first sale. Of all winning bids submitted by entering firms, 88 percent were jointly submitted bids. Of the 128 firms winning OCS leases, 75 of these never won a tract bidding as an individual firm submitting a solo bid. It is doubtful that the magnitude of entry into OCS leasing would have been as great had joint bidding been prohibited."14/

14/ Wilcox, <u>Op</u>. <u>cit</u>., pp. 92-93

Joint Bidding in OCS Lease Sales

Sale Number	Date	State	Percent Joint Bids	Percent High Joint Bids
1	10/13/54	La	18	19
2	11/ 9/54	Tex	24	32
3	7/12/55	La	39	29
4	7/12/55	Tex	24	18
5	5/29/59	Fla	96	96
6	8/11/59	La	29	37
7	2/24/60	La	42	54
8	2/24/60	Tex	15	17
9	3/13/62	La	24	20
10	3/16/62	La	27	22
11	3/16/62	Tex	0	0
12	10/ 9/62	La	42	44
13	5/14/63	Cal	14	7
14	4/28/64	La	14	22
15	10/ 1/64	Ore	70	68
16	10/ 1/64	Wash	58	64
17	3/29/66	La	28	35
18	10/18/66	La	37	46
19	12/15/66	Cal	71	100
20	6/13/67	La	38	48
21	2/ 6/68	Cal	74	75
22	5/21/68	Tex	49	32
23	11/19/68	La	45	69
24	1/14/69	La	40	55
25	12/16/69	La	28	25
26	7/21/70	La	19	26
27	12/15/70	La	47	51
28	11/ 4/71	La	36	46
29	9/12/72	La	52	68
30	12/19/72	La	77	73
31	6/19/73	Tex/La	80	92
32	12/20/73	Miss/Ala/La	62	63
33	3/28/74	La.	68	73
34	5/29/74	Tex.	60	61
35	12/11/75	Calif.	45	43
36	10/16/74	La.	62	57
37	2/ 4/75	Tex.	52	43
38	5/28/75	La./Tex	53	52
38a	7/29/75	La./Tex	54	55

Source: Outer Continental Shelf Statistical Summary, Bureau of Land Management, U.S. Department of the Interior. Computations to Sale #32 drawn from Wilcox (1975).

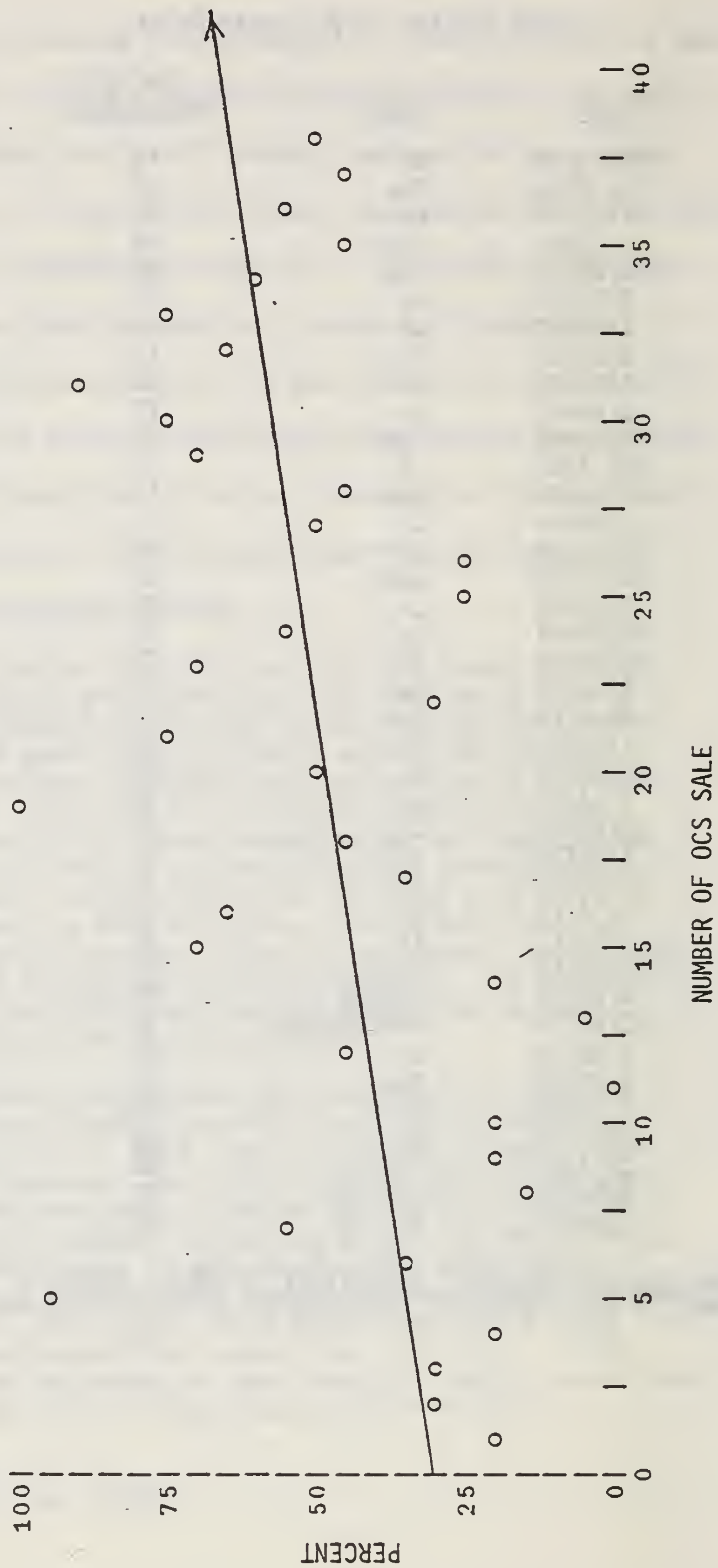

Figure 3 Winning Joint Bids as a Percentage of all Winning Bids in Each OCS Sale

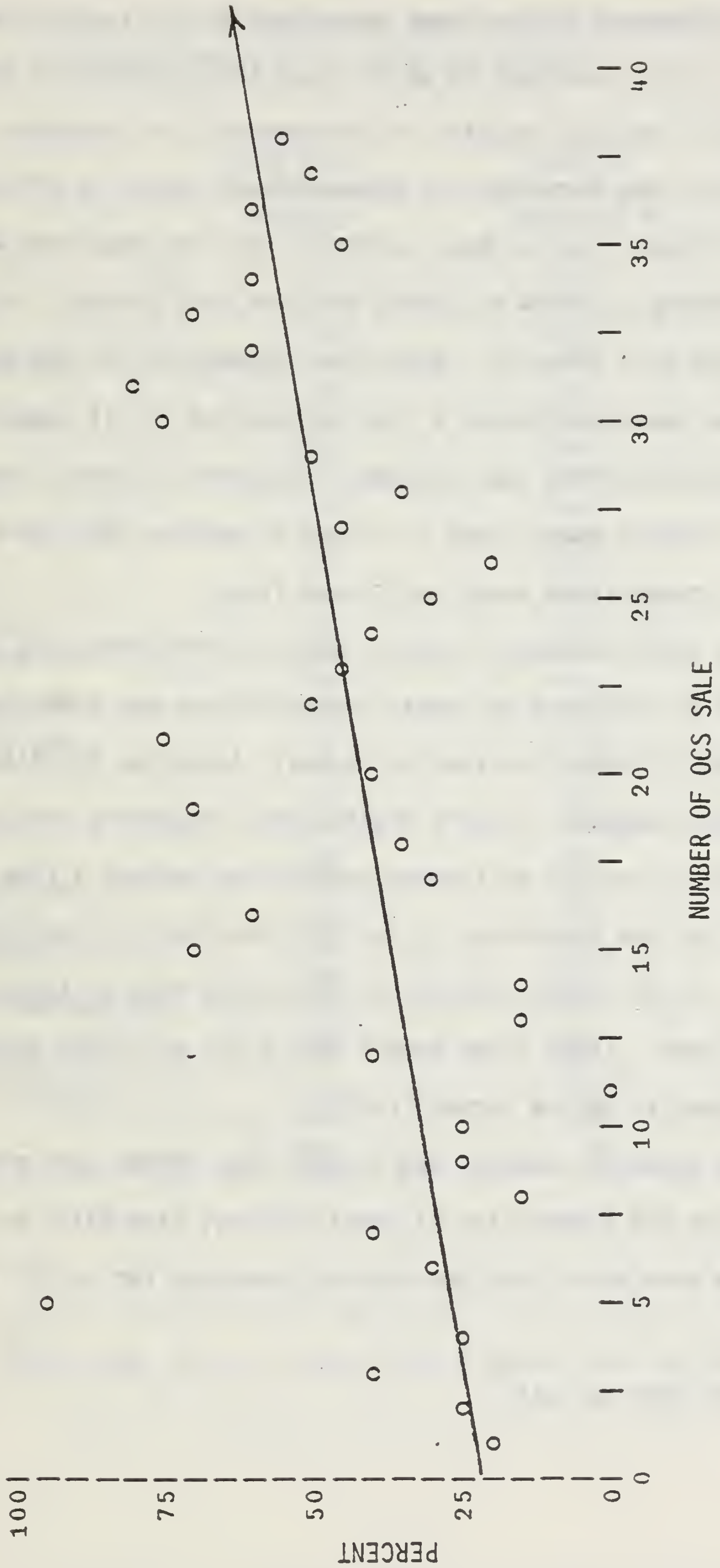

Figure 4 Joint Bids as a Percentage of All Bids in Each OCS Sale

While entry appears to have been encouraged by the availability of joint bidding, it does not seem to be the case that competition among firms already "in" the OCS industry is increased by this practice. One might suppose that the firm that can buy one-third shares in OCS ventures will compete in three times as many auctions; that the eggs that went in one basket before will now be spread out over many baskets. Wilcox's evidence does not bear this out. Even after accounting for the effects of assets on the number of tracts a firm is involved in, it appears that more frequent joint bidding does not mean involvement in more tracts. This important finding means there is reason to believe that joint bidding <u>reduces</u> competition among the larger firms.

Given that joint bidding is used by smaller firms which may be more risk-averse, is it also used by large firms which--we may assume--do not need the help of this risk-sharing device? According to Wilcox, smaller firms have engaged in joint bidding more frequently than larger firms. In Table 3.2 we see an inverse correlation between a firm's current assets and the percentage of its OCS bids that are submitted jointly. This is, of course, not to say that joint bids of large firms are not significant. Large firms submit more bids, and their shares of joint bids tend to be the larger fractions.

Still more recently, Gaskins and Vann[15/] have thrown some more light on the effects on OCS competition of joint bidding, especially by large firms. We have seen above that the high bid received for an OCS tract

---

[15/] Gaskins and Vann <u>op</u>. <u>cit</u>.

Table 3.2 - Assets and Utilization of Joint Bidding by Firms Participating in 20 or more OCS Leases

Firm	Percent of High Bids Submitted Jointly	Current Assets Million $	Number Tracts Involved
Shell	10	1234	276
Sun	12	560	82
Exxon	35	6791	199
St. California	49	2010	276
Superior	52	64	44
Gulf	57	2652	164
Texaco	58	2820	137
Phillips	60	903	73
Tenneco	64	1065	44
Union	78	615	152
Mobil	83	2205	138
Arco	83	1082	206
Continental	84	978	164
St. Indiana	86	1466	187
Signal	87	617	31
Kerr-McGee	90	270	51
La. Land & Expl.	91	39	35
Skelly	94	169	62
Amerada	94	470	33
Marathon	96	366	26
Burmah	96	156	26
Allied Chemical	97	561	32
Pennzoil	98	257	47
Cities Service	99	584	150
Getty	100	450	117
Texas E. Transmission	100	162	41
Cabot	100	139	39
American Petrofina	100	87	21
Pennzoil Offshore	100	30	33
Mesa	100	24	27
Felmont	100	6	37
(Placid)	(52)	na	(33)

Source: Wilcox, op. cit., p. 105; Current Assets from Moody's (1972)

is correlated strongly with the number of bidders who participate in the competition for the tract. But, of course, both variables are similarly influenced by the true value of the tract -- a quantity ordinarily not observable until many years after the lease sale has taken place. Would it still be the case that high bid goes up with the number of bidders if value of the tract could be controlled for? For true value of the tract Gaskins and Vann substitute the USGS estimate of fair market value that is constructed for purposes of rejecting inadequate high bids. They find that the relationship still holds: the ratio of the high bid to the USGS evaluation goes up as the number of bidders increases. The more valuable tract draws more bidders and hence wins a more than proportionately higher bid. These ratios for a number of recent OCS sales are shown in Table 3.3.

Gaskins and Vann next split out some of the data in Table 3.3 according to whether the high bid was submitted by a major or a non-major firm. They find (see Table 3.4) that high bids still go up with number of bidders, whether the winner is a major or not. But--and most importantly--the major's average winning bid is lower than the non-major's average winning bid, even when the effects of tract value and number of bidders are accounted for. They conjectured that this observed difference in bids derives from an information advantage gained by the majors in the process of joint-bid negotiations:

> "The potential impact of joint bidding among major buyers on the bidding results depends in part on certain stylized facts about bidding consortia in OCS sales.
>
> - Major bidders evaluate all tracts in a sale to some extent, before any joint bidding agreement is reached.

Table 3.3

Ratio of High Bids to the
Government's Evaluation for Recent Sales

Bids/ Tracts	June 1973	Dec. 1973	Mar. 1974	May 1974	Oct. 1974	Feb. 1975
1	.50	.53(2,306)	1.00(4,565)	2.42(1,962)	2.67(1,627)	1.24(885)
2	.71	.79(4,322)	1.55(6,909)	2.39(3,274)	3.17(2,295)	3.09(780)
3-4	.50	1.03(8,624)	1.90(8,316)	3.35(2,640)	9.64(1,766)	1.96(1,974)
5-7	1.14	1.64(13,495)	2.38(9,707)	11.94(2,724)	9.54(2,888)	1.96(2,468)
8+	1.59	1.13(41,967)	6.16(10,417)	4.24(8,721)	8.76(2,729)	16.79(391)

The numbers in parenthesis are the average government estimate of the value of the tracts in each category (in thousands of dollars).

Table 3.4

Ratios of High Bids to Estimated Values for
Selected Groups of Bidders for March 1974 Sales

Bids/ Tracts	All Companies	Majors	Non-Majors
1	1.00	.66	1.12
2	1.55	1.45	2.14
3-4	1.90	2.23	1.57
5-7	2.38	1.84	6.89
8+	6.16	5.71	10.07

Source for Tables 3.3 and 3.4: Gaskins and Vann (1975)

- Major bidders frequently enter different bidding consortia in the same sale.

- Lesser bidders are not typically included in consortia involving major bidders.

"These stylized facts are derived from review of the composition and behavior of bidding consortia in recent sales, testimony at a public hearing on joint bidding held in June 1974 and conversations with various OCS bidders.

"The decision to bid jointly or not on a given tract is made at a meeting of a group of potential bidders at which participants reveal to each other their bidding intentions for a block of prospects. The typical procedure is that first mutual interest in certain tracts is established and then all interested parties reveal their prospective bids. A joint bidding agreement may then be reached under which the consortium agrees on a bid level and no participant in the original meeting may exceed that bid in the subsequent sale.

"We are concerned with the fact that the process of forming joint bidding consortia reveals the bidding intentions of the participants on all of the tracts under discussion. In particular, it is possible to learn from such a meeting that none of the other participants intend to bid on certain tracts.

"Consider the following illustrative example. Companies x, y and z attend a meeting to discuss the possibility of rendering joint bids for tracts A through G. Company x indicates that it is interested in bidding on tracts A, B, D and G. Company y wants to bid on B, C, D and F. Company z declares it is only interested in B, C and E. This meeting may result in a joint bid for tracts B and D but it also indicates to Company x that it will receive no competition from y or z on tracts A and G, etc.

"It seems intuitively clear that information as to the number of rival bidders should be valuable. Consider the case of a bidder who knows the actual number of bidders on each tract while his rivals know only the average number across all tracts. By entering a bid only on those tracts which will receive fewer than the average number of bids an informed bidder could make higher expected profits than an uninformed bidder, even if the informed bidder made no adjustment in the level of his tendered bids. Information that you were to be the single bidder on a prospect should be particularly valuable.

"The bidding intentions of major bidders is much more valuable information than the bidding intentions of a lesser bidder, because of the higher a priori probability of a bid on any given tract from a major bidder. Because consortia including major bidders generally exclude other potential bidders, this valuable information is available to some and not to all bidders.

"We now have a possible mechanism that will allow some bidders (major bidders who participate in consortia with other major bidders) to continually win some tracts on favorable terms. The restrictive nature of the consortia among the major bidders is a barrier to entry which allows extra-normal expected profits in some segments of the market for OCS leases.

"This story about the information generated by the joint bidding process leads us to predict that major bidders should win tracts on more favorable terms than non-major bidders.

"On September 29, 1975, the Department of the Interior banned joint bidding on the OCS among companies that produce more than 1.6 million barrels a day world-wide of crude oil, natural gas and liquified petroleum.

"On December 22, 1975, with the signing of the Energy Policy and Conservation Act, the same prohibition became law."16/

16/ See Appendix

4. THE CASE FOR A JOINT BIDDING BAN IN ONSHORE OIL AND GAS

Recent History of Federal Onshore Oil and Gas Leasing

In Calendar 1975, BLM held 23 competitive sales of onshore oil and gas leases on known structures. The average of the 324 parcels leased was 264 acres, was bid on by 1.9 bidders, and brought a high-bid bonus of $17,966. USGS assessed 197 of these parcels as being of only "nominal" value--meaning, usually, that the value was less than $10 per acre; the average USGS assessment for the parcels judged to be of more than nominal value was $13,841.[17/]

Tables 4.1 and 4.2 give comparable data on competitive leases issued and bonuses received for the calendar years 1973 and 1974, broken down by State. The aggregates and the averages are seen to be of roughly the same order of magnitude for the three years. Tables 4.3 and 4.4 give number and acreage data on non-competitive leases issued in 1973 and 1974. In 1973 we see that 311 oil and gas tracts were competitively leased, and 13,038 tracts were noncompetitively leased. Only, that is to say, about a <u>fortieth</u> of the tracts leased were distributed in a competitive sale. Moreover, in that same year, the average size of the competitively leased tract was 287 acres, as against 1,060 acres for the average noncompetitively leased tract, so <u>less than one per cent</u> of the acreage leased for oil and gas rights in 1973 was leased in competitive sales. The relative differences in 1974 are similar.

17/ Source: Conservation Division, USGS

Table 4.1

—Competitive mineral leases issued and bonuses received, 1973

Type of mineral by State	Public lands			Acquired lands			Total		
	Number	Acres leased	Bonus received	Number	Acres leased	Bonus received	Number	Acres leased	Bonus received
Oil and gas									
Arkansas				8	4,727	$408,412.18	8	4,727	$408,412.18
Colorado	35	10,345	$67,970.07				35	10,345	67,970.07
Kansas	1	160	2,416.00	1	160	3,481.60	2	320	5,897.60
Louisiana	1	120	4,450.00				1	120	4,450.00
New Mexico	87	30,061	899,329.59				87	30,061	899,329.59
Oklahoma	31	1,823	231,879.89	2	123	2,477.00	33	1,946	234,356.89
Utah	35	12,852	158,175.37				35	12,852	158,175.37
Wyoming	109	28,744	424,315.63	1	200	462.00	110	28,944	424,777.63
Total oil and gas	299	84,105	1,788,536.55	12	5,210	414,832.78	311	89,315	2,203,369.33
Phosphate									
Utah	1	133	33,634.51				1	133	33,634.51
Grand total	300	84,238	1,822,171.06	12	5,210	414,832.78	312	89,448	2,237,003.84

Source: Public Land Statistics 1973, Bureau of Land Management.

Table 4.2

—Noncompetitive mineral leases issued, 1973

Type of mineral by State	Public lands		Acquired lands		Total	
	Number	Acres	Number	Acres	Number	Acres
Oil and gas						
Alabama	3	881	25	21,357	28	22,238
Arizona	133	233,042			133	233,042
Arkansas	15	8,107	75	80,505	90	88,612
California	163	49,029			163	49,029
Colorado	982	949,755	98	39,207	1,080	988,962
Florida			1	2,361	1	2,361
Idaho	578	1,197,462			578	1,197,462
Illinois			2	785	2	785
Kansas	1	419	6	13,809	7	14,228
Kentucky			19	20,718	19	20,718
Louisiana	12	1,568	75	35,969	87	37,537
Michigan	4	281	40	24,517	44	24,798
Mississippi	8	1,620	293	129,207	301	130,827
Montana	1,644	1,814,499	450	601,365	2,094	2,415,864
Nebraska	24	10,274	8	6,572	32	16,846
Nevada	698	782,023			698	782,023
New Mexico	1,235	1,014,246	21	11,504	1,256	1,025,750
New York			3	4,925	3	4,925
North Dakota	80	23,114	112	29,209	192	52,323
Ohio			2	201	2	201
Oklahoma	92	12,955	42	33,160	134	46,115
South Dakota	73	95,786	2	249	75	96,035
Texas			54	23,496	54	23,496
Utah	2,484	4,026,400	16	8,056	2,500	4,034,456
Virginia			1	1,993	1	1,993
West Virginia			19	28,466	19	28,466
Wyoming	3,401	2,455,882	44	21,208	3,445	2,477,090
Total oil and gas	11,630	12,677,343	1,408	1,138,839	13,038	13,816,182
Phosphate						
Montana	1	1,172			1	1,172
Utah	1	133			1	133
Wyoming	2	1,680			2	1,680
Total phosphate	4	2,985			4	2,985
Potassium						
California	1	440			1	440
Grand total	11,635	12,680,768	1,408	1,138,839	13,043	13,819,607

Source: Public Land Statistics 1973, Bureau of Land Management.

Table 4.3

—Competitive mineral leases issued and bonuses received, 1974

Type of mineral by State	Public lands			Acquired lands			Total		
	Number	Acres leased	Bonus received	Number	Acres leased	Bonus received	Number	Acres leased	Bonus received
Oil and gas									
Colorado	67	18,921	$575,446.55	1	120	$690.00	68	19,041	$576,136.55
Mississippi	----	----	----	11	940	39,977.20	11	940	39,977.20
Montana	51	11,709	109,298.00	----	----	----	51	11,709	109,298.00
New Mexico	21	2,747	816,396.97	----	----	----	21	2,717	816,396.97
Oklahoma	18	1,205	189,713.49	2	70	1,754.50	18	1,275	191,467.99
Texas	----	----	----	1	500	8 [illegible]	1	500	8 845.00
Utah	7	3,626	33,244.00	----	----	----	7	3,626	33,241.00
Wyoming	116	25,169	518,995.14	2	240	1,262.40	118	25,409	520,257.54
Total oil and gas	278	63,377	2,243,094.15	17	1,870	52,529.10	295	65,247	2,295,623.25
Oil shale									
Colorado	2	10,184	328,093,600.36	----	----	----	2	10,184	328,093,600.36
Utah	2	10,240	120,704,000.00	----	----	----	2	10,240	120,704,000.00
Total oil shale	4	20,424	448,797,600.36	----	----	----	4	20,424	[illegible]
Coal									
Alabama	1	2,388	23,890.00	----	----	----	1	2,388	23,890.00
Colorado	1	241	16,877.00	----	----	----	1	241	16,877.00
Pennsylvania	----	----	----	2	80	4,050.00	2	80	4,050.00
Utah	1	1,360	350,009.00	----	----	----	1	1,360	350,009.00
Total coal	3	3,989	390,776.00	2	80	4,050.00	5	4,069	304,826.00
Grand total	285	87,790	451,431,470.51	19	1,950	56,579.10	304	89,740	451,488,049.61

Source: Public Land Statistics 1974, Bureau of Land Management.

Table 4.4

—Noncompetitive mineral leases issued, 1974

Type of mineral by State	Public lands		Acquired lands		Total	
	Number	Acres	Number	Acres	Number	Acres
Oil and gas						
Alabama	8	1,998	38	34,576	46	36,574
Arkansas	60	92,459	46	102,784	106	195,243
Arizona	138	274,937	----	----	136	274,937
California	214	80,560	4	119	218	80,679
Colorado	1,552	1,763,081	189	125,833	1,741	1,888,914
Idaho	367	754,348	----	----	367	754,348
Indiana	----	----	2	2,432	2	2,432
Kentucky	----	----	17	13,147	17	13,147
Louisiana	4	279	80	33,436	84	33,715
Michigan	2	85	42	11,063	44	11,128
Mississippi	8	478	360	225,586	368	226,064
Montana	765	798,058	183	143,746	948	941,804
Nevada	443	553,943	----	----	443	553,943
New Mexico	976	794,666	23	35,310	999	829,976
New York	----	----	9	17,501	9	17,501
North Dakota	52	7,792	176	73,445	228	81,237
Ohio	----	----	18	8,558	18	8,558
Oklahoma	62	26,702	50	27,504	112	54,206
Pennsylvania	----	----	1	181	1	181
South Dakota	464	699,297	45	45,046	509	744,343
Texas	32	23,814	----	----	32	23,814
Virginia	----	----	4	7,342	4	7,342
Utah	1,057	1,951,509	3	3,458	1,060	1,954,967
West Virginia	----	----	117	84,364	117	84,364
Wyoming	3,646	2,723,591	39	27,674	3,685	2,751,265
Total oil and gas	9,348	10,547,577	1,444	1,023,585	11,292	11,571,162
Coal						
Colorado	2	281	----	----	2	281
Kentucky	----	----	1	1,282	1	1,282
Total coal	2	281	1	1,282	3	1,563
Potassium						
Arizona	4	6,313	----	----	4	6,313
Sodium						
California	2	560	----	----	2	560
Wyoming	4	8,203	----	----	4	8,203
Total sodium	6	8,763	----	----	6	8,763
Grand total	9,860	10,563,434	1,445	1,024,867	11,305	11,588,301

Source: Public Land Statistics 1974, Bureau of Land Management.

Table 4.5

—Mineral leases on public lands as of June 30, 1974

State	Oil and gas		Coal		Other		Total	
	Number	*Acres*	*Number*	*Acres*	*Number*	*Acres*	*Number*	*Acres*
Alabama	243	46,097	2	2,588	—	—	245	48,685
Alaska	2,223	4,314,719	4	2,593	—	—	2,227	4,317,312
Arizona	370	529,019	—	—	[1] 14	13,330	384	542,349
Arkansas	282	275,555	—	—	—	—	282	275,555
California	2,031	632,120	1	80	[2] 22	29,254	2,054	661,454
Colorado	9,631	8,361,152	112	122,156	[3] 6	20,614	9,749	8,503,922
Florida	174	175,775	—	—	—	—	174	175,775
Idaho	903	1,803,766	—	—	[4] 86	45,055	989	1,848,821
Kansas	198	60,195	—	—	—	—	198	60,195
Louisiana	358	45,030	—	—	—	—	358	45,030
Michigan	136	88,332	—	—	—	—	136	88,332
Mississippi	247	22,126	—	—	—	—	247	22,126
Montana	9,552	8,573,373	17	36,232	[5] 29	22,193	9,598	8,631,798
Nebraska	206	163,173	—	—	—	—	206	163,173
Nevada	2,457	1,076,436	—	—	[6] 33	35,478	2,490	1,111,914
New Mexico	12,559	8,325,642	29	41,038	[7] 117	170,077	12,705	8,536,757
North Dakota	768	259,015	18	16,236	[8] 2	1,005	788	276,256
Oklahoma	812	115,455	53	87,014	[9] 2	640	867	203,109
Oregon	115	224,688	3	5,403	—	—	118	230,091
South Dakota	1,138	1,204,404	—	—	—	—	1,138	1,204,404
Utah	15,059	14,372,665	196	266,976	[10] 45	53,782	15,300	14,693,423
Washington	2	1,357	2	521	—	—	4	1,878
Wyoming	38,331	21,866,867	89	199,701	[11] 55	91,544	38,475	22,158,112
Total	97,795	72,536,961	526	780,538	411	482,972	98,732	73,800,471

[1] 6 Sodium, 9,035 A.; 8 gold, silver, copper, 4,295 A.
[2] 1 Phosphate, 1,009 A.; 5 potash, 8,953 A.; 16 Sodium, 18,692 A.
[3] 1 Potash, 632 A.; 3 Sodium, 9,798 A.; 2 oil shale, 10,184 A.
[4] 86 Phosphate, 45,055 A.
[5] 28 Phosphate, 22,033 A.; 1 Sodium, 160 A.
[6] 11 Potash, 16,600 A.; 11 Sodium, 15,327 A.; 2 silica sand, 481 A.; 4 sand & gravel, 2,110 A.; 3 gold, silver, copper, 480 A.; 1 tungsten, 400 A.; 1 feldspar, 80 A.
[7] 116 Potash, 169,997 A.; 1 Sodium, 80 A.
[8] 2 Sodium, 1,005 A.
[9] 1 Silica sand, 160 A.; 1 gilsonite, 480 A.
[10] 8 Phosphate, 8,800 A.; 25 Potash, 41,772 A.; 12 gilsonite, 3,210 A.
[11] 11 Phosphate, 13,919 A.; 44 sodium, 77,625 A.

Source: Geological Survey, U.S. Department of the Interior.

The corresponding total bonus receipts from these competitive sales are small: \$1.8 million in 1973, \$2.2 million in 1974, and \$5.8 million in 1975.

A comparison of onshore and offshore competitive leasing of oil and gas rights is instructive. In Table 4.6 some of the relevant totals and averages for 1974 are shown.

Table 4.6
COMPETITIVE OIL AND GAS LEASES ON FEDERAL LANDS, 1974

	Onshore	Offshore
No. of tracts leased	295	356
Total acreage leased	65,247	1,762,158
Total bonus received (\$1,000)	2,296	5,022,861
Average acres/tract	221	4,950
Average bonus/tract	7,783	14,109,160
Average bonus/acre	35.18	2,850.40

Source: Public Land Statistics 1974, Bureau of Land Management.

Somewhat fewer tracts are leased onshore; they are, typically, only a twentieth the size of an OCS tract; most importantly, they bring only one-hundredth the bonus per acre.

Competition for these onshore oil and gas lands has not been intense. As we saw in the case of OCS, the value of the high bid received for a parcel in a competitive sale is expected to increase with the number of bidders in the competition, but not quite in proportion. As the number of bidders gets large, we would ordinarily expect the high bid to more closely approach some underlying "true" market value, which, of course, should be correlated with the USGS estimate of value.

The 1975 data do bear out these relationships. A statistical regression analysis shows that a good fit to the data is provided by a formula in which high bid for a parcel increases with both the number of bidders and the USGS estimate--less than proportionately with the former, and more than proportionately with the latter.18/

18/ The regression referred to is

$$\ln b = .157 + \underset{(.10)}{.77} \ln n + \underset{(.05)}{1.05} \ln g \qquad R^2 = .57$$

where n stands for the number of bidders and g for the USGS estimate of the tract's value or $10 times the acreage where it was judged to be only nominal value. The numbers in parentheses are the standard errors of the coefficient estimates. Perhaps a more convenient way to read the formula is in the following mathematically equivalent representation:

$$b = 1.17 n^{.77} g^{1.05} .$$

In this form it is easy to see what one more bidder contributes to the high bid received in a sale: for instance a fourth bidder adds $100 \times (4/3)^{.77} - 100$ or 24% of the bonus received. Such estimates should perhaps not be taken too seriously, but the regression does indicate a substantial value, in terms of bonus received, to competition.

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These estimates do indicate a substantial value, in terms of bonus received, to an increase in the number of competitors submitting bids.

Compared then either to the enormous Federal OCS leasing operations, or to the onshore noncompetitive Federal oil and gas leasing, onshore competitive leasing of oil and gas rights on Federal lands is a small business.

That onshore competitive leasing remains small is a direct result of the limited authority granted by the Mineral Leasing Act of 1920 to the Secretary of the Interior to employ competitive leasing in granting rights. The relevant parts of that statute (as amended and supplemented), 30 USC 226 (a)-(c), follow:

TITLE 30--MINERAL LANDS AND MINING

§226. Lease of oil and gas lands.

(a) Authority of Secretary.

All lands subject to disposition under this chapter which are known or believed to contain oil or gas deposits may be leased by the Secretary

(b) Lands within known geologic structure of a producing oil or gas field: competitive bidding.

If the lands to be leased are within any known geological structure of a producing oil or gas field, they shall be leased to the highest responsible qualified bidder by competitive bidding under general regulations in units of not more than six hundred and forty acres, which shall be as nearly compact in form as possible, upon the payment by the lessee of such bonus as may be accepted by the Secretary and of such royalty as may be fixed in the lease, which shall be not less than 12-1/2 per centum in amount or value of the production removed or sold from the lease.

(c) Lands not within geologic structure of a producing oil or gas field: first qualified applicant.

If the lands to be leased are not within any known geological structure of a producing oil or gas field, the person first

> making application for the lease who is qualified to hold a lease under this chapter shall be entitled to a lease of such lands without competitive bidding. Such leases shall be conditioned upon the payment by the lessee of a royalty of 12-1/2 per centum in amount or value of the production removed or sold from the lease.

The most received in 1975 for any of the competitive parcels was $340,000 for a 160 acre tract on which six bids were received. Of the 324 parcels sold competitively during the year, 214 drew only one bid; the distribution of bids is shown in Table 4.7.

Table 4.7

No. of Competitively Leased Oil and Gas Tracts for Which 1, 2, 3 . . . Bids were Submitted in 1975

No. of bidders	No. of parcels
1	214
2	48
3	22
4	13
5	4
6	10
7	3
8	6
9	3
10	0
11	1
Total	324

Source: U.S. Geological Survey.

Out of the 615 bids submitted in this year, only four were joint bids, and only two of these were high bids.

Competitive leasing, we see, is restricted to those lands within "known geologic structures." Current opinion among informed geologists

is that most of the good lands on known structures have already been leased and explored; that what remains is fringe acreage where significant findings are improbable.

The risks of offshore and onshore drilling compared. As explained in Section 2 joint bidding may be defensible if it encourages competition by enabling risk-averse firms to pool risks. We have seen in Section 3 that such risk sharing through the device of joint bidding has proved to be a very popular practice in OCS bidding. Moreover, analysts who have studied the history of OCS bidding have concluded that joint bidding has in fact improved competition for leases through its facilitation of entry into the industry. The question we wish to look at here is whether the risks in onshore oil and gas leasing are substantial enough to justify allowing a practice which has the potential of reducing competition by consolidating many bids into one. What are the risks in onshore oil and gas exploration on lands within known structures?

The risk of an oil and gas drilling undertaking involves three components: the investment at risk, the probabilities of the various outcomes, and the magnitudes of those outcomes.

The investment at risk in buying a lease includes the bonus paid for the lease (or at least that part of the bonus that is not allowed as a tax write-off) and those exploration and drilling costs that are incurred prior to determination of the outcome of the "gamble."

We have already seen that the average size of an OCS tract is twenty times that of an onshore competitively leased tract. Not only

is the bonus for the typical OCS tract thereby bigger, the per-acre bonus is almost 100 times larger. The average OCS tract in 1974 sales brought approximately $14 million; the average onshore tract brought about $8,000. As far, then, as bonuses go, an OCS tract is a thousand times the gamble that an onshore tract is. In the data from earlier years this same general difference persists.

A good part of the investment at risk in a drilling venture is the cost of drilling--although this is not the whole cost of exploration. Geologists in USGS concerned with estimation of tract values estimate that on OCS tracts typically two or three exploratory dry holes will be drilled before a decision is made that the tract has no potential for development. The costs of each of these exploratory wells may vary from $1-1.5 million for wells in the Gulf of Mexico to $4 million off California and $8 million off Alaska.[19/] (These costs increase exponentially with drilling depths). These drilling investments then--from $3 million to perhaps $15-20 million--are at risk of total loss in an OCS exploration venture.

Some idea of the relative size of risk in the onshore venture can be gained from examination of aggregate data for the whole U.S. In Tables 4.8 and 4.9 industry data on drilling costs is given, respectively, for all wells and for offshore wells. There we see that the depth of the typical offshore well is much greater than that of an onshore well. The cost per well appears to be on the order of five to one.

19/ USGS estimates.

What are the probabilities of wins and losses in onshore and offshore ventures? The gamble represented by the leasing and exploration of an oil and gas tract is not accurately represented by a coin-flip win-or-lose model involving the drilling of a single hole. Nevertheless, if the exploration and drilling practices onshore and offshore are not too dissimilar, some idea of the relative probabilities can be gained by simply looking at the fractions of exploratory wells that turn out to be dry holes. Table 4.10 shows these fractions onshore, offshore, and in selected states for New Field Wildcat tests in 1968. The "fraction dry" may be taken as an estimate of the dry hole risk. We see that the probability of a dry hole is very high--.90--but not significantly different onshore and offshore. Because we do not quite know how to classify exploration in the category of interest here, namely, newly leased oil and gas tracts on Federal lands within known structures, Tables 4.11 and 4.12 are presented to display dry hole risks in less risky drilling. Table 4.11 shows all exploratory drilling; the results are about the same. Table 4.12 shows developmental drilling; here the risks are much less, of course, and offshore drilling is relatively less risky.

In summary: Bidding risk involves (1) the bonus, (2) the value of the prize to be won, (3) the costs of exploration and drilling, and (4) the probability of a dry hole. Comparing offshore and onshore competitively leased oil and gas tracts we find--even when we adjust for tract size by comparing on a per-acre basis--bonus is very much greater offshore, drilling cost is greater offshore, prize differences

Table 4.8

ESTIMATED COSTS OF DRILLING AND EQUIPPING WELLS, BY DEPTH INTERVALS — 1974

TOTAL UNITED STATES*

	Depth Interval (feet)	*Total Number of Wells, Footage Drilled, and Costs* Oil Wells	Gas Wells	Dry Holes	Total	*Average Depth and Cost Per Well* Oil	Gas	Dry	Total
Wells		2.553	209	967	3.729				
Footage	0 - 1.249	2.159.318	169.959	737.015	3.066.292	846	813	762	822
Costs $		40.064.803	3.569.697	10.037.343	53.671.843	15.693	17.080	10.380	14.393
Wells		2.714	1.086	1.697	5.497				
Footage	1.250 - 2.499	4.857.131	2.200.906	3.197.406	10.255.443	1.790	2.027	1.884	1.866
Costs $		90.277.537	42.742.204	41.837.036	174.856.777	33.264	39.357	24.654	31.809
Wells		2.313	1.353	1.905	5.571				
Footage	2.500 - 3.749	7.176.543	4.323.254	5.951.085	17.450.882	3.103	3.195	3.124	3.132
Costs $		140.291.682	78.134.805	76.332.058	294.758.545	60.654	57.749	40.069	52.909
Wells		1.489	1.119	1.964	4.572				
Footage	3.750 - 4.999	6.571.553	4.879.268	8.579.180	20.030.001	4.413	4.360	4.368	4.381
Costs $		135.521.025	86.957.778	111.346.497	333.825.300	91.015	77.710	56.694	73.015
Wells		2.190	1.281	2.448	5.919				
Footage	5.000 - 7.499	13.235.994	7.880.118	15.081.905	36.198.017	6.044	6.152	6.161	6.116
Costs $		315.343.432	175.750.111	295.413.189	786.506.732	143.992	137.198	120.675	132.878
Wells		1.230	847	1.456	3.533				
Footage	7.500 - 9.999	10.593.775	7.240.491	12.589.938	30.424.204	8.613	8.548	8.647	8.611
Costs $		321.867.000	220.965.380	353.867.911	896.700.291	261.680	260.880	243.041	253.807
Wells		380	437	820	1.637				
Footage	10.000 - 12.499	4.188.273	4.888.229	9.066.165	18.142.667	11.022	11.186	11.056	11.083
Costs $		184.774.855	223.225.542	305.914.264	713.914.661	486.250	510.814	373.066	436.112
Wells		127	211	278	616				
Footage	12.500 - 14.999	1.702.454	2.816.155	3.765.060	8.283.669	13.405	13.347	13.543	13.448
Costs $		105.441.071	173.987.600	202.383.014	481.811.685	830.245	824.586	727.996	782.162
Wells		63	83	119	265				
Footage	15.000 - 17.499	1.008.567	1.331.218	1.909.959	4.249.744	16.009	16.039	16.050	16.037
Costs $		73.540.133	115.164.783	129.338.753	318.043.669	1.167.304	1.387.528	1.086.880	1.200.165
Wells		9	32	35	76				
Footage	17.500 - 19.999	165.261	593.446	650.854	1.409.561	18.362	18.545	18.596	18.547
Costs $		18.195.426	55.976.254	65.060.760	139.232.440	2.021.714	1.749.258	1.858.879	1.832.006
Wells		5	37	24	66				
Footage	20.000 and over	106.373	808.019	519.422	1.433.814	21.275	21.838	21.643	21.724
Costs $		15.008.815	90.066.169	68.591.875	173.666.859	3.001.763	2.434.221	2.857.995	2.631.316
Total Wells		13.073	6.695	11.713	31.481				
Total Footage		51.765.242	37.131.063	62.047.989	150.944.294	3.960	5.546	5.297	4.795
Total Costs $		1.440.325.779	1.266.540.323	1.660.122.700	4.366.988.802	110.176	189.177	141.733	138.718

* Includes the following states which are not shown separately: Arizona, Georgia, Idaho, Iowa, Maryland, Missouri, Nevada, North Carolina, South Dakota, Tennessee, and Virginia

Source: 1974 Joint Association Survey of the U.S. Oil and Gas Producing Industry. Sect. 1: Drilling Costs. American Petroleum Institute, Independent Petroleum Assoc. of America, and the Mid-Continent Oil and Gas Assoc. (March, 1976) pp. 8-9

Table 4.9

ESTIMATED COSTS OF DRILLING AND EQUIPPING WELLS, BY DEPTH INTERVALS — 1974

TOTAL OFFSHORE

		Total Number of Wells, Footage Drilled, and Costs				*Average Depth and Cost Per Well*			
	Depth Interval (feet)	Oil Wells	Gas Wells	Dry Holes	Total	Oil	Gas	Dry	Total
Wells		—	—	2	2				
Footage	0 - 1,249	—	—	2,085	2,085	—	—	1,043	1,043
Costs $		—	—	305,274	305,274	—	—	152,637	152,637
Wells		1	1	2	4				
Footage	1,250 - 2,499	2,340	2,255	3,036	7,631	2,340	2,255	1,518	1,908
Costs $		139,815	149,145	836,002	1,124,962	139,815	149,145	418,001	281,241
Wells		24	1	7	32				
Footage	2,500 - 3,749	80,010	3,015	22,198	105,223	3,334	3,015	3,171	3,288
Costs $		3,884,151	163,503	3,142,677	7,190,331	161,840	163,503	448,954	224,698
Wells		20	3	14	37				
Footage	3,750 - 4,999	86,094	13,046	61,900	161,040	4,305	4,349	4,421	4,352
Costs $		3,895,102	1,584,359	7,933,242	13,412,703	194,755	528,120	566,660	362,505
Wells		45	25	124	194				
Footage	5,000 - 7,499	292,968	159,873	787,532	1,240,373	6,510	6,395	6,351	6,394
Costs $		21,545,313	16,003,601	83,388,575	120,937,489	478,785	640,144	672,489	623,389
Wells		89	49	144	282				
Footage	7,500 - 9,999	756,629	429,381	1,258,416	2,444,426	8,501	8,763	8,739	8,668
Costs $		65,156,022	39,742,783	117,075,806	221,974,611	732,090	811,077	813,026	787,144
Wells		49	40	79	168				
Footage	10,000 - 12,499	547,339	449,260	879,452	1,876,051	11,170	11,232	11,132	11 167
Costs $		43,106,076	40,188,146	75,475,060	158,769,282	879,716	1,004,704	955,381	945,055
Wells		24	21	39	84				
Footage	12,500 - 14,999	322,472	281,189	530,302	1,133,963	13,436	13,390	13,597	13,500
Costs $		30,840,061	28,149,323	51,103,167	110,092,551	1,285,003	1,340,444	1,310,338	1,310,626
Wells		1	14	10	25				
Footage	15,000 - 17,499	15,062	222,387	157,600	395,049	15,062	15,885	15,760	15,802
Costs $		1,028,132	23,379,233	18,080,023	42,487,388	1,028,132	1,669,945	1,808,002	1,699,496
Wells		—	1	1	2				
Footage	17,500 - 19,999	—	18,415	18,000	36,415	—	18,415	18,000	18,208
Costs $		—	2,246,630	1,428,840	3,675,470	—	2,246,630	1,428,840	1,837,735
Wells		—	—	—	—				
Footage	20,000 and over	—	—	—	—	—	—	—	—
Costs $		—	—	—	—	—	—	—	—
Total Wells		253	155	422	830				
Total Footage		2,102,914	1,578,821	3,720,521	7,402,256	8,312	10,186	8,816	8,918
Total Costs $		169,594,672	151,606,723	358,768,666	679,970,061	670,335	978,108	850,163	819,241

Source: 1974 Joint Association Survey of the U.S. Oil and Gas Producing Industry. Sect. 1: Drilling Costs. American Petroleum Institute, Independent Petroleum Assoc. of America, and the Mid-Continent Oil and Gas Assoc.

Table 4.10

New-Field Wildcat Tests Drilled in the U.S. 1968

(Offshore-Onshore and Selected States)

	Producers	Dry Holes	Total Wells	Fraction Dry
Offshore	13	114	127	.89
California	1	8	9	.89
Louisiana	8	87	95	.92
Texas	4	19	23	.83
Onshore	480	4,162	4,942	.90
Colorado	32	407	439	.93
Wyoming	40	413	453	.91
Total	493	4,576	5,069	.90

Source: American Petroleum Institute, Petroleum Facts and Figures (1971)

Table 4.11

Exploratory Tests Drilled in the U.S. 1968

(Offshore-Onshore and Selected States)

	Producers	Dry Holes	Total Wells	Fraction Dry
Offshore	82	339	421	.81
Alaska	1	5	6	.83
California	3	20	23	.87
Louisiana	68	284	352	.81
Texas	10	30	40	.75
Onshore	1,211	7,247	8,458	.86
Colorado	21	249	270	.92
Wyoming	81	503	584	.86
Total	1,293	7,586	8,879	.85

Source: American Petroleum Institute, Petroleum Facts and Figures (1971)

Table 4.12

Development Wells Drilled in the U.S. 1968

(Offshore-Onshore and Selected States)

	Producers	Dry Holes	Total Wells	Fraction Dry
Offshore	968	126	1,094	.12
Alaska	75	6	81	.07
California	302	2	304	.01
Louisiana	583	113	696	.16
Texas	8	5	13	.38
Onshore	15,351	5,401	21,720	.25
Colorado	137	87	224	.39
Wyoming	456	152	608	.25
Total	16,319	5,401	21,720	.25

Source: American Petroleum Institute, Petroleum Facts and Figures (1971)

are unknown, and dry-hole risk differences are ambiguous. Perhaps the most important feature of the comparison is the typical difference in the sizes of the ventures, offshore and onshore. The investor in an OCS tract, typically twenty times the size of an onshore tract, cannot as easily balance his land portfolio so as to average out losses.

On the basis of the evidence examined, it cannot be argued that, dollar for dollar, an investment in an onshore competitive oil and gas tract is less of a risk than investment in an OCS tract. But since the onshore leases come in smaller bundles, undivided participation in a lease is much less a risk onshore than in OCS. Investment in the typical competitively leased onshore oil and gas tract would seem to be within easy reach of most interested firms.

We conclude that there is little justification for joint bidding in the competition for competitively leased Federal onshore oil and gas tracts. Although the probability is high that any such venture will not discover oil or gas, the magnitude of the typical operation in terms of the investment at stake is so small that no pooling of risk is required to encourage competition. So long, then, as joint bidding is freely permitted there exists the potential that industry may use this device to obtain Federal leases at less than their true market value.

<u>We recommend, then, that the restriction on joint bidding, exactly as stated in Section 105(a-d) of the Energy Policy and Conservation Act of 1975 (42 USC 6213), should be extended to cover the bidding for any right to develop crude oil, natural gas, and natural gas liquids on Federal lands other than those located on the Outer Continental Shelf.</u>

5. THE CASE FOR A JOINT BIDDING BAN IN COAL [20]

20/ This Section draws heavily on a recently completed study, Enhancing Competition for Federal Coal Leases, prepared for the Office of Policy Analysis, Dept. of the Interior, by Richard A. Clark, Robert C. Lind, and Robert Smiley; Science Applicaton, Inc. (Jan. 1976).

In considering the leasing of Federal coal lands we have very little recent experience to turn to for study. In Table 4.3 above, we saw that in 1974 only five small coal leases were granted. In 1973 the Secretary of the Interior declared a moratorium on coal leasing to allow the Department to reformulate its leasing policy. Now the moratorium has been lifted, a new leasing policy has been announced, and it is expected that Federal coal leasing will resume.

Unlike an oil and gas tract, the uncertainties connected with the development of a coal tract have much more to do with such things as future prices, transportation, mining methods, and end-use technology, than with magnitude of the resource in place on the tract. Typically, the prospective lessee of a coal tract knows roughly what amounts of coal underlie the tract. The information he gathers by drilling after the granting of the lease is mainly for the purpose of refining his estimates and laying out detailed mining plans, not for determination of whether the resource is present. For leasing policy purposes this is an extremely important difference. The Federal lessee of a coal tract need not necessarily bear the risk associated with the development of, say, a slurry pipeline to carry his coal to market. The uncertainty surrounding the pipeline is not resolved simultaneously with his leasing the land; rather, it remains to be resolved over time. Meanwhile, the lessee has the opportunity to explore ways to share, and possibly to divest himself entirely of, this risk. On the other hand, an oil and gas lessee who is the sole participant in exploration of his tract bears the whole risk surrounding the magnitude of the find.

We argued earlier that where bidding risk is high we would expect the practice of joint bidding to increase competition by encouraging entry into bidding contests. Where bidding risk is low we would, on the contrary, expect that little new participation is encouraged, and that many multiple-bid contests become few-bid contests. In the case of coal, we believe that the extent of the risk necessarily borne by the bidder (as opposed to risks borne by the users farther down the line) is sufficiently small that our attention is more usefully focused on the competitive characteristics of the industry of potential coal bidders and on the characteristics of the land that might affect the nature of the competition for tracts. In consequence, the next sections review the current organization for coal development, the industry -- consisting of coal companies, oil companies, utilities, and others -- and the land ownership patterns and their expected effects on competition.

5.1 Organization of Coal Leasing

The Mineral Leasing Act of 1920 confers broad authority on the Secretary of the Interior to lease Federally owned coal. Two leasing systems, competitive and non-competitive, are authorized.

Where sufficient information as to the coal reserves exists, the Secretary is required to offer coal for leasing on a competitive basis. The Department confers the lease on the individual or firm which bids the highest bonus amount for the right to lease the tract under prespecified rental and royalty terms.

Where the existence or workability of coal is unknown, the Secretary is authorized by the Act to issue prospecting permits, for terms of two years, on tracts no larger than 5,120 acres. If within the allowed time period a permit holder demonstrates the existence of coal in commercial quantities, a non-competitive lease for all or part of the tract is granted. Unlike the competitive leasing system, the lease is conferred free of any lump sum payment, with only the annual rental fee and a fixed royalty on extracted coal being charged the lessee.

Within the broad framework of the 1920 statute, the Department of the Interior has considerable discretion in the formulation of overall leasing policies and in the setting of specific lease terms. In particular, the Department has the authority to set rental and royalty rates, to determine which tracts shall be leased, to decide when to hold sales and when to grant or deny prospecting permit applications, to stipulate reclamation and environmental protection procedures, and to set minimum production requirements.

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Aside from setting overall policy, most of Interior's leasing authority has been delegated to the Bureau of Land Management (BLM) and the Geological Survey (GS). The authority to determine whether or not leases, permits, or licenses are to be issued has been delegated to BLM.

GS conducts studies of the coal resources in the public lands and classifies the lands as to coal occurrence and value. GS uses this information to identify "Known Coal Leasing Areas" in which competitive leasing will take place. In addition, GS is largely responsible for making geological, engineering, and economic value determinations. Once BLM grants a permit or lease, the GS assumes responsibility for operations relating to the location and extraction of coal. GS seeks, through approval of operations plans, to ensure compliance with the relevant leasing statutes, Departmental regulations, lease terms, and environmental and rehabilitation provisions.

Under the administrative framework described, 537 coal leases, covering nearly 800,000 acres of public coal lands, have been issued to private parties. The manner in which the leases were granted, their terms, and the ultimate uses to which they have been put have recently become matters of intense discussion.

In 1973 the Secretary of the Interior declared a moratorium on all coal leasing until an improved programmatic plan could be developed. The resulting document,[21/] including a description of the new Energy Minerals

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21/ Final Environmental Impact Statement -- Proposed Federal Coal Leasing Program, BLM, Department of the Interior (1975).

Activity Recommendation System (EMARS), was released in January 1975. EMARS outlines a plan whereby BLM takes the initiative in planning the orderly development of western coal lands through a system of competitive leasing. In 1976, the Secretary announced his intention to resume coal leasing. The first sale is expected to take place early in 1977.

What level of competition can we expect to prevail in these forthcoming sales? To examine this question we look below to characteristics of the coal industry and the markets for coal, and we examine certain potential barriers to entry into this industry.

5.2 Competition and the Structure of the Industry

Concentration levels and trends are usually measured by a ratio. A four firm concentration ratio is the share of coal production accounted for by the four largest firms. The four, eight, and twenty firm concentration ratios for coal production in 1972 were 30.4 per cent, 40.4 per cent, and 55.1 per cent.[22/] (While these concentration levels are not alarmingly high, their trend is worth noting. The same figures for 1955 were 16.5 per cent, 24.0 per cent and 37.5 per cent). Efficient scale at the plant (mine) level does not require concentration of this magnitude nor are changes in the size of mine required for efficient operations sufficient to explain this trend. In such a climate the effect of government policy (including leasing) on national concentration should be carefully evaluated.

First, fully 60 per cent of coal production lies outside the top eight firms -- there is a large competitive fringe. Second, there are a large number of potential entrants who use coal as an input (including oil companies, natural gas companies, public utilities, and metals companies). Many of these companies already mine coal, and others who don't may enter the bidding to prevent themselves from being foreclosed from future supply, or if they see bids being let for abnormally low dollar amounts. Abnormally low bids, with the pursuant large profits or rents will trigger entry by some

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22/ Duchesneau , Thomas D., Competition in the U.S. Energy Industry, Ballinger Publishing Company, Cambridge, Massachusetts (1975)

potential entrants wishing to share in the rents. The existence of potential competition can affect the nature of bidding and other practices in the industry, even though the potential entrants may never actually enter.

Already in the industry, among the 15 largest coal producers, we find as parent firms four coal companies, four metal companies, four oil companies, a public utility, a natural gas company and an aircraft company.[23/]

How many firms will bid on lease tracts and how vigorous will the bidding be? While bidding will not be limited to operating companies, there were at least 19 companies operating strip mines producing two million tons or more per year in 1974.[24/] It is likely that all of these 19 firms possess the technical ability to operate a large strip mine in the northern great plains area. Subject to the locational monopoly issue discussed immediately below, all of these firms can thus be viewed as potential bidders on Federal coal leases.

Ownership patterns can give firms differential advantages. If one firm owns the surface or water rights for the area covered by the tract, or owns alternate sections with those being leased (both sets of sections being necessary for efficient mining), other firms may be discouraged from

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23/ Hearings Before Subcommittee on Minerals, Materials, and Fuels. U.S. Senate, March 13, April 1 and 2, 1974, page 282.

24/ Coal Data, 1974, page 17.

bidding on the tract. The firm which owns the rights would then have a clear advantage over other potential bidders. With the exception of ownership patterns, there do not appear to be physical factors that should lead to such advantages in coal leasing bidding.

But what of competition in the local markets? It could be that each of the major coal companies has staked out an area (say State), and the other firms will allow it dominance in that area in return for non-interference in its own area.[25/] If this "area of influence" or "area of dominance" hypothesis is valid, coal mining companies should have holdings concentrated in only one or perhaps two States. To determine whether this behavior is occurring, major lease-holdings were examined in four western States: Montana, Wyoming, Colorado, and Utah. Of the 13 companies holding leases for 5,000 acres or more in any of the four States, five held leases in only one State, four in two States, two in three States, and two companies held leases for 5,000 acres or more in each of the four States. While we cannot resolve the "area of dominance" hypothesis solely on the basis of this evidence, there do appear to be a substantial number of firms with extensive holdings in several States. Eight firms hold leases for at least 5,000 acres in two or more States.

Further evidence on the locational monopoly question is available from the State of Montana. Five companies are actively engaged in strip mining in Eastern Montana currently.[26/] Four of these firms and 14 others have assembled or have pending coal-water rights packages for mining in the

25/ Mead found behavior similar to this in the Douglas Fir industry.

26/ Energy Companies Active in Montana, Northern Plains Resource Council, February 1975.

future. There are enough firms interested in mining in Montana to provide the potential for vigorous competition for coal leases.

The establishment of local monopolies is helped if the scope of the market is local or regional. Coal markets in the past have been best described as regional, allowing some firms to build up regional power due to their domination of the smaller regional markets. Hogarty argues that recent events such as anti-pollution requirements and transportation improvements have led to a "tendency for the scope of geographic markets to increase. We offer the tentative conclusion that the industries comprising the energy (input) sector -- uranium, gas, oil and coal are (at least) national in scope." 27/

All the factors outlined above, including national and local concentration and market conditions, difficulty in enforcing collusion, and the growing scope of the market, indicate there is little in the structural nature of the coal industry at present concentration levels that would lead to less than vigorous bidding on Federal coal leases.

A barrier to entry into the industry can exist if the optimal sized mine is a substantial portion of total market size. When minimum efficient scale is a substantial proportion of the market size, a potential entrant has two choices; it can enter at efficient scale and depress the market price, or it can enter at less than efficient scale and incur higher costs than the firms already in the industry. Due to the two unattractive alternatives facing potential entrants, existing firms can raise prices above average costs and still not precipitate entry.

27/ Appendix A in Duchesneau, op. cit.

Minimum efficient scale in coal mining is unfortunately not a well defined quantity, depending on the amount of overburden and size of the seam among other factors. In addition, the increase in costs from operating at a scale less than minimum efficient scale is difficult to estimate. Moyer estimated that ". . . strip mines achieve optimum scale output at an annual output of at least several million tons." If we take, as minimum efficient scale, the output required to feed an efficient scale coal gasification plant, we have a figure in the neighborhood of 10 million tons/year. A mine of this size would produce 1.67 per cent of 1974 output of bituminous and lignite coal and about half that percentage in 1985. Moore considers multiplant economies and considers them to be minimal.[28] The size of an efficient coal mine in relation to market size does not appear to constitute a significant entry barrier.

Even though the size of an efficient mine in relation to market size does not pose a barrier to entry, the investment capital required to construct such a mine may. If a large amount of capital is required to build a plant of efficient scale, some (otherwise qualified) potential entrants may be discouraged from entering if they face disproportionately high borrowing costs in raising the required capital, or may be precluded from entering altogether if they are unable to raise the capital at any cost.

Katell, Hemingway, and Berkshire of the Bureau of Mines estimate that $42,050,100 is required for an efficient scale (9.2 million tons/year)

28/ Appendix B in Duchesneau, op. cit.

Northern Great Plains mine.29/ This may be sufficiently large to preclude many of the smaller firms from entering this market (large scale Northern Great Plains mining) and thus from bidding on lease tracts best suited for mines of this size. Westmoreland Coal Co., for example, was the 12th largest producer in 1972 and had assets in 1973 of $117 million. Using conventional financial means, such as retained earnings or long term debt issues, one or more new mines of this magnitude could well tax Westmoreland's ability to raise capital.30/

The effect of leasing only very large tracts might be to limit bidding to only a few oil companies and large utilities. This result is not certain, however. Investment bankers interviewed by Clark, et al, were of the opinion that, if the tracts offered are very large, joint bidding will become a common practice in the coal industry, just as it has in OCS.

While capital requirements may pose a problem for smaller coal companies, they should not constitute a barrier for many potential entrants. The larger oil companies, utilities, and steel companies should experience little difficulty in raising capital of this order of magnitude.

29/ Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines, Sidney Katell, E. L. Hemingway and L. H. Berkshire, Bureau of Mines Information Circular - 8661, revised.

30/ Investment bankers interviewed by Clark, et al, expressed the opinion that the applicant's technical and financial management expertise were far more important than size of the bidding company in the lenders decision to grant funds. If an applicant is turned down in an application for funds to initiate a new mine, the lenders felt that reason is more likely to be lack of financial management capability rather than the size of the firm.

Will bonus bidding which requires a front-end capital commitment substantially increase the capital requirement barrier to entry? The answer, of course, depends on the size of the bid, which depends on the size of the lease, the future price of coal and many other factors. To get a rough idea of the effect of bonus bidding on entry barriers, Clark, et al, asked investment bankers the following question: With non-bidding capital requirements of $30-50 million, would a $5 million bonus bid capital requirement be sufficient to prevent any firms from raising the required capital? To arrive at this total bid figure they took the bid per ton of the most competitive auction ever held (nine bidders in a 1971 Campbell County, Wyoming, auction) and multiplied it by tons of coal required to support for 20 years the Katell-estimated mine described above, and then multiplied it by five. In the opinion of the several investment bankers interviewed, the additional capital requirement posed by bonus bidding of this magnitude would be sufficient to eliminate at most one or two firms. Marginal firms would already be eliminated by the capital requirement for the mine itself or by a perceived lack of financial management skills. Considering the combination of emerging financial instruments (such as project financing) and the fact that many marginal firms are eliminated from borrowing the capital required to mine the coal for managerial expertise reasons, bonus bidding should not eliminate a large number of firms.

Established marketing and distribution practices further complicate entry into the coal industry. Most coal currently mined and nearly all of the Northern Great Plains coal is sold under long term contract. The purchaser, a utility or some other user, arranges for a steady flow of coal over a period of 10 to 30 years. Such purchasers are attempting to reduce risk of coal supply interruption and will often not be agreeable to a 20-year contract with a very young firm such as a new entrant. New entrants often are forced to supply the spot market which is considerably more risky than the demand conditions facing an established firm (long term contracts).

We conclude that, with regard to industry structure, there is a potential for very competitive bidding on government-owned lease tracts. Although some smaller firms will be eliminated if bonus bids are high, there are a large number of firms currently active in coal mining in the upper Great Plains areas. In addition, there are many likely entrants into the industry (and into the lease bidding) including utilities, steel and natural gas companies.

5.3 Competition and Patterns of Ownership of Coal Lands

We now turn from the structure of the coal producing industry to analyze the patterns of ownership of the coal itself and their implications for Federal leasing policy. Much western coal is privately owned and with a few notable exceptions, namely certain railroads, this ownership is widely dispersed. In addition to privately owned coal reserves, the States and Indian tribes own significant reserves. However, the most significant single owner of U.S. coal reserves if the Federal Government, and most of its reserves are located in the West. There are two characteristics relating to Federal ownership that may have a significant affect on the development of U.S. coal and on competition for Federal coal leases.

The first is the checkerboard pattern of ownership that occurs in some of the richest coal fields in the West, such as the Powder River Basin in Wyoming. Checkerboarding occurs where alternate sections are owned privately, sometimes by a single owner. The problem that this poses is that a coal deposit which comprises a logical mining unit -- i.e., the deposit that should be mined as a single unit in order to maximize the economic value of a mine -- lies across a number of sections owned by the government and one or more private owners. For efficient mining of the coal a single mining unit should be created. This requires that the mining operation acquire both a Federal lease and the rights to mine that part of the logical mining unit that is privately owned. The checkerboard pattern of ownership may constitute a significant impediment to efficient mining of coal in the checkerboard, reduce the value of any Federal lease to a potential bidder,

and reduce competition as well. The total effect may be inefficient mining and a significant reduction in Federal leasing revenues.

The second situation of interest is where the Federal Government has sold or granted land to private owners, but has retained the mineral rights. There are significant areas of the West where Federally owned coal deposits are under land to which the surface rights are privately owned. In many cases, the surface owner is a coal company that expects to obtain a Federal lease for the coal. If, by its position as the surface owner, the coal company has an advantage over other bidders that might compete for the coal lease, competition and Federal leasing revenues are reduced. This situation presents many of the same problems as checkerboarding.

In what follows we analyze how checkerboarding and the separation of surface and subsurface ownership will affect the value of Federal coal deposits and the degree of competition for Federal coal leases.

When a logical mining unit spans both Federal and private land, the potential profit to a mining operator from mining the entire unit is greater than the sum of the potential profits from mining the Federal and private deposits separately. This is true because there are decreasing average production costs with increasing scale up to the size of the logical mining unit. Heavy fixed costs such as building a drag line, or bringing in a railroad spur, produce this phenomenon.

The degree to which production costs decrease with increases in scale is critical. If the cost decreases are substantial, then checkerboarding

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presents a serious threat to competition. Informed opinion suggests that the potential gains from forming a logical mining unit in many cases are large.

Further, all competitors for a Federal lease do not have the same information. All may have information about the Federal coal deposit, but only the owner of the private land has full access to information about his deposit under present law. This gives him a great advantage. Only he can estimate with confidence the value of the logical mining unit. Finally, in order to limit competition, the owner of land in the checkerboard would have an incentive to refuse to lease the rest of the logical mining unit to any competitor who won a Federal lease. This would punish firms that dared to compete and would reduce the value of a Federal lease and reduce competition.

These tendencies could seriously limit competition for Federal leases. Further, even if there were some competition, little or none of the increase in value from forming a logical mining unit would be captured by the Federal Government.

Checkerboard ownership patterns, then, impede competition and reduce Federal lease revenues. Under these circumstances, joint bidding is not likely to offer firms much encouragement to enter the competition. Indeed, joint bidding would only appear here to dampen further the little competition that may be hoped for.

We turn now to surface rights. A mining company that obtains a Federal coal lease must have the necessary rights to access on the surface in order to mine the deposit. Under the Stock Raising Homestead Act, the principal statute under which minerals have been reserved to the United States when the surface was disposed of, the lessee of the Federal mineral rights may proceed to exploit the minerals as long as he compensates the surface owner for any costs that are imposed on him. Similar provisions exist under other statutes. Under this interpretation, the separation of surface and subsurface ownership should not present a major barrier to exploitation of the coal deposits. However, observers such as William Hynan of the National Coal Association point out that this is an area of the law that is essentially untested and uncharted, and that anyone who would try to carry out a mining operation without obtaining the prior consent of the surface owner would in all likelihood become embroiled in litigation that could last for years. At the present time, no one is quite sure what the course of events will be in this area of the law and, therefore, there is a high degree of uncertainty unless the owner of the Federal coal lease also owns the surface rights or has a prior agreement with the surface owner for mining the coal.

It is clear that whatever the coal owners' legal rights may be with respect to the effect of mining activities on the surface, the threat of legal action by the surface owner, and the uncertainty about what compensation

may be required in the absence of a prior agreement, may be sufficient to impede competition and in some cases to stop development of Federal deposits prior to some agreement for rights to the surface. If a bidder wins a Federal lease, he must strike a bargain with the company owning the surface rights with regard to compensation for the costs of mining, or otherwise face litigation.

5.4 Joint Bidding on Coal Leases

The decision on whether to prohibit joint bidding for coal leases is dependent upon other considerations than those previously discussed for offshore and onshore oil and gas.

When a coal tract is open for competitive bidding, the extent of the resource has already been estimated with some degree of certainty by the bidders and by the Department of the Interior. Thus, the risk of bidding for a lease is primarily limited to: (1) obtaining the equipment to develop the coal so it is available when needed, (2) finding a means to transport the coal, (3) obtaining rights of way, and (4) finding a buyer for the coal. Some of these risks are important, but there will not be any "dry holes" when a coal tract is developed.

We have seen that private ownership patterns in western coal lands give reason for serious concern about the levels of competition that can be expected to prevail in contests for individual parcels of Federal land. Both surface/subsurface ownership rights and checkerboarding of Federal coal lands are important in determining the competition for Federal leases. We have, therefore, argued that the ownership problems can be expected to affect competition adversely and, consequently, to diminish Federal bonus revenues.

We judge that the competition that can be expected in the bidding for western Federal coal lands is too fragile to allow the further dilution that unrestricted joint bidding could bring. Further, we do not believe that joint bidding can significantly reduce the disincentives to competition

that land ownership patterns create. We conclude that a restriction on joint bidding, similar to that contained in Section 105 of the Energy Policy and Conservation Act of 1975 (42 USC 6213) should be extended to cover the bidding for any right to develop coal on Federal lands.

The joint bidding restriction in the case of OCS defined a set of firms no two of which were allowed to bid jointly with each other. The restricted firms were defined in terms of annual production (See Appendix B). Applying the same reasoning to coal, we find (See Table 5.1) that two firms are notably larger producers -- the Peabody Group and the Consolidation Group, both incidentally subsidiaries of larger firms. These two firms each produce more than twice the output of the third ranking firm, the Island Creek Group, after which the annual tonnages drop off very gradually to the eighth ranking firm.

We recommend that the firms which are to be restricted from bidding with each other in joint coal ventures shall be those firms producing more than 25 million tons of coal annually.

Table 5.1

Top 15 Coal-Producing Groups in 1974

Compiled by Keystone Coal Industry Manual
Top 15 Producer Organizations

Production of the top 15 operating organizations in the industry in 1974 (see table below) totaled 280,333,970, against 294,264,372 for the 15 ranking groups in 1973.

Collectively, the 15 leaders showed a loss of 4.7% from 1973, while the bituminous industry as a whole lost an estimated 2 million tons in 1974. Four of these 15 companies produced more in 1974 than in 1973. Together, the leading 15 produced 47.5% of the estimated 1974 bituminous tonnage, compared with 49.5% for the top 15 in 1973.

Group or Company	1974 Tonnage	% Change 1973 to 1974	1973 Tonnage	% Change 1972 to 1973	Standing 1974	Standing 1973	Standing 1972	Standing 1970	Standing 1965
Peabody Group	68,104,076	−2.5	69,918,787	−2.3	1	1	1	1	1
Consolidation Group .	51,753,933	−14.4	60,477,363	−6.8	2	2	2	2	2
Island Creek Group ...	20,848,000	−8.8	22,879,320	+1.2	3	3	3	3	3
Amax Group	19,948,871	+19.7	16,657,552	+1.6	4	5	5	5	4
Pittston Group	17,381,911	−7.5	18,796,305	−8.9	5	4	4	4	5
U. S. Steel (c)	16,389,000	+1.0	16,222,038	−0.1	6	6	6	8	9
Arch Mineral Group	13,878,539	+10.6	12,538,631	+12.3	7	8	11	n.a.	n.a.
Bethlehem Mines (c) ..	13,347,625	−5.5	14,129,000	+5.9	8	7	7	6	7
North American	9,771,563	−9.3	10,783,000	−10.0	9	9	9	12	12
Peter Kiewit Group ...	9,697,000	+58.4	6,113,568	+96.5	10	17	24	—	—
Old Ben	9,451,880	−12.8	10,846,684	−3.4	11	10	10	10	11
Eastern Associated ...	7,697,823	−27.6	10,640,063	−15.0	12	11	8	7	8
Westmoreland	7,580,575	−13.9	8,808,651	−2.8	13	12	13	11	13
Pittsburg & Midway ...	7,528,174	−6.6	8,064,089	+8.1	14	14	14	13	10
Utah International	6,955,000	−5.8	7,389,321	+7.1	15	15	15	14	31
Total	280,333,970	−4.7	294,264,372	−2.4					

(C) Captive

Source: <u>Keystone Coal Industry Manual 1975</u>, McGraw-Hill (1975) p. 498.

6. THE CASE FOR A JOINT BIDDING BAN IN OIL SHALE

THE CASE FOR A JOINT BIDDING BAN IN OIL SHALE[31/]

Most of the quality oil shale deposits in the U.S. are found in the Green River Basin of the Rocky Mountains. This relatively concentrated area of approximately 25,000 square miles, extending over parts of Colorado, Utah, and Wyoming, contains about 600 billion barrels of crude oil in high-grade oil shale, and perhaps 1,200 billion barrels of oil in lower-grade oil shale. An estimated 72 per cent of the oil shale land in the Green River Basin is public domain, and this land contains an estimated 80 per cent of the high-grade deposits.

The Mineral Lands Leasing Act of 1920 gives the Secretary of the Interior broad discretionary power in setting lease terms for Federal oil shale lands, including the length of time for which the lease shall be granted, the royalty rate to be paid, and any "covenants relative to methods of mining, prevention of waste, and productive development."[32/] The statute includes a provision for an annual rental of 50 cents per acre, but this rental can be credited against the year's royalty payments. In order to encourage development, the Secretary is empowered to waive both the royalty and rental payments in the first five years of the lease.

31/ The following description of the prospects for leasing of Federal oil shale lands makes extensive use of the lucid exposition presented in Chapter 8 of Report to the Federal Trade Commission on Federal Energy Land Policy: Efficiency, Revenue, and Competition, Bureau of Competition and Bureau of Economics (October, 1975).

32/ U.S. Department of the Interior, Prospects for Oil Shale Development-Colorado, Utah, and Wyoming, May, 1968, p. 3.

Royalty rates are renegotiable at the end of each 20-year period. The size of any one lease is limited to 5,120 acres of land, and no individual or corporation is permitted to hold more than one lease in the United States.33/

An effort at oil shale leasing was made in 1968, when the Interior Department, without soliciting tract nominations from industry, selected three oil shale tracts in Colorado for leasing.34/ One tract received two bids, a second tract received one bid, and the third tract received no bids. All bids were rejected because they were far below the Department's "minimum acceptable bids."

In response to President Nixon's energy message of June 4, 1971, the Secretary of the Interior initiated "a leasing program to develop our vast oil shale resources, provided that environmental questions can be satisfactorily resolved."35/ Two tracts each in Colorado, Utah, and Wyoming were offered for lease, one each month starting in January 1974. The tracts were offered using competitive bonus bids with fixed royalties and fixed rental payments. Bidders were allowed to make the bonus payments in five equal annual installments. In addition, development

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33/ On April 24, 1974, in a memorandum to the Director of the Bureau of Land Management, the Solicitor of the Department of the Interior ruled that a person, association, or corporation may hold interests in more than one oil shale lease if the pro rata shares of such leases in terms of acreage do not constitute more than an aggregate of 5,120 acres.

34/ For the 1968 lease provisions, see "Oil Shale Lease Form No. 1-Rev. December 10, 1968," in 33 F.R. No. 242, December 13, 1968, pp. 18523-18525.

35/ U.S. Department of the Interior, "News Release," November 28, 1973.

expenditures made within the first three years may be credited against the fourth bonus payment, and development expenditures made in the fourth year may be credited against the fifth bonus payment. If the lease is surrendered before the fifth anniversary, the final two bonus payments are forgiven. These conditions were intended to decrease the risk to bidding firms, and thereby to make the leases more attractive to industry than had been the case in 1968.

Of the six tracts offered for lease in 1974, the four tracts in Colorado and Utah were actually leased. The Department announced in April 1975 that it will offer two additional tracts for a joint industry/ Government effort to accelerate the development of _in situ_ shale oil recovery.

Oil shale deposits show considerable diversity with respect to thickness, oil content, and accessibility. Hence, the characteristics of any particular oil shale deposit cannot be known without exploratory effort. However, pre-lease core drilling and other exploration are capable of establishing a deposit's characteristics with considerable precision. Therefore, the acquisition of an oil shale deposit is subject to much less uncertainty with respect to ultimate resource availability than, for example, the acquisition of an offshore oil or gas property. In this respect oil shale is similar to coal.

Technology for oil shale development is subject to more uncertainty. The technique for recovering oil from oil shale with which there is the most experience is mining combined with surface retorting. However, some observers believe that the technique that may ultimately be more

efficient is _in situ_ recovery, by which the resource is retorted while still in the ground and liquid shale oil rather than oil shale rock is brought to the surface.[36/] Neither of these techniques has been established on a commercial scale. Mining and surface retorting have been conducted in demonstration projects considerably smaller than the 50,000 to 100,000 barrels-per-day scale envisaged for commercial production. _In situ_ projects are still mostly in the experimental stage.

Because there has been no experience with large-scale commercial shale oil production, estimates of commercial production costs remain uncertain. Although numerous estimates have been generated, it is difficult to compare them since they vary so widely with respect to assumptions about size of plant, mining technology, retorting technology, oil shale characteristics, etc. According to cost estimates prepared by the Bureau of Mines for the Project Independence Oil Shale Task Force, a 100,000 barrel-per-day facility would have capital costs of $520 million or $600 million, depending upon whether underground or surface mining techniques were used. However, a more recent estimate by the Colony Development Operation suggests that a 50,000 barrel-per-day facility might have capital costs above $800 million.[37/] Not only are the cost estimates themselves uncertain; they also do not include the development and shakedown costs normally associated with implementing a new technology.

36/ _Potential Future Role of Oil Shale: Prospects and Constraints_, _op. cit._, pp. 259-297; _Prospects for Oil Shale Development-Colorado, Utah, and Wyoming_, _op. cit._, pp. 40-73; and _Energy from Oil Shale: Technical, Environmental, Economic, Legislative, and Policy Aspects of an Undeveloped Energy Source_, report prepared for the U.S. House of Representatives, Committee on Astronautics, Subcommittee on Energy, 93d Cong., 1st sess., 1973, pp. 9-14.

37/ _Business Week_, April 28, 1975, pp. 87, 88.

An additional problem which might deter development is fear of technological obsolescence. As more experience is gained, new oil shale processing techniques will probably be developed which are cheaper and better than the processes installed by initial entrants. Recognizing this possibility, some firms may be reluctant to enter. Indeed, uncertainty concerning such changes may have been an important consideration in the decisions of some early shale technology developers to defer investing in commercial conversion plants.

In all, uncertainty about the technological characteristics and costs of commercialization combine with uncertainty about the economic environment in which shale oil will be sold to make shale oil development investment quite risky and costly.

There is no conclusive indication whether potential oil shale investors are risk-averse or not, or whether they are more or less risk averse than other energy companies. It has been noted that only token bids were offered in the 1968 lease sale, whereas substantial bids were received in the 1974 sale. However, the low bids in 1968 might be explained by the bidders' reaction to the stringent patent and disclosure provisions or by the relatively low price of conventional crude oil at that time, rather than by risk aversion.

38/ See U.S. House of Representatives, Permanent Select Committee on Small Business, Subcommittee on Activities of Regulatory Agencies, Energy Data Requirements of the Federal Government, Part II, Oil Shale, Hearings, 93d Cong., 2d session, January 28, 1974, pp. 58-62.

If the amount of money that must be offered to acquire oil shale rights is substantial, small operators may be precluded from bidding, with possibly detrimental consequences for the competitiveness of the industry. Table 6.1 presents data on the 1974 prototype leasing sales showing various measures of what acquiring an oil shale lease cost. The bids per acre ranged from $8,000 to $41,300, while the bids per ton of estimated oil-bearing shale ranged from 11.3 cents to 22.1 cents, and the bids per gallon of estimated oil content ranged from 0.38 cents to 0.74 cents. These amounts appear quite small when the world price of crude oil is above $10 per barrel, or 24 cents per gallon. Evidently, bidders expected substantial development and production costs to squeeze profits, or they applied a large risk premium in view of the prevailing uncertainties, or some combination of the two.

Nevertheless, the magnitude of the winning bids was large in absolute terms and within the range of the Outer Continental Shelf oil and gas bonus bids which have aroused concern as barriers to entry. The special five-year payment, cancellation, and development offset provisions reduce their riskiness somewhat. But even so, the size of the bonus payments was large enough to evoke concern about the ability of small firms to undertake such an investment.

There is reason to believe that these bonus payments may have been larger than would characterize a full-scale shale oil leasing program. The tracts leased in 1974 were among the most attractive for oil shale development. Most privately held oil shale properties are of significantly lower quality; and other Government properties, apparently including the

TABLE 6.1 --Bids Received, 1974 Prototype Oil Shale Leasing Program Sales

Tract	Firms bidding for tract	Bonus bid (million dollars)	Bonus bid per acre (thousand dollars)
C-a	1. *Standard Oil Co. (Indiana) and Gulf Oil Co.	210.3	41.3
	2. Sun Oil Co.	175.0	34.3
	3. Marathon Oil Co., American Petrofina Co. of Texas, Phelps Dodge Corp.	80.0	15.7
	4. Atlantic Richfield Co., Ashland Oil Inc., The Oil Shale Corp.	63.3	12.4
	5. Shell Oil Co.	63.0	12.4
	6. The Carter Oil Co.	33.1	6.5
	7. Occidental Oil Shale, Inc.	16.4	3.2
C-b	1. *Atlantic Richfield Co., The Oil Shale Corp., Ashland Oil, Inc., Shell Oil Co.	117.8	23.1
	2. Geokinetics Group (Andarka Production Co., Koch Industries, Inc., Mesa Petroleum Co., Murphy Oil Corp., Signal Oil and Gas Co.)	52.5	10.3
U-a	1. *Phillips Petroleum Co., Sun Oil Co.	75.6	14.8
	2. Occidental Oil Shale, Inc.	25.0	4.9
	3. Geokinetics Group (Andarka Production Co., Diamond Shamrock Corp., Koch Industries, Inc., Murphy Oil Corp., Signal Oil and Gas Co., Allied Chemical Corp.,	3.8	0.7
U-b	1. *White River Shale Oil (Standard Oil Company of Ohio, Phillips Petroleum Co., Sun Oil Co.)	45.1	8.8
	2. Geokinetics Group (Andarka Production Co., Murphy Oil Corp., Signal Oil and Gas Co.)	11.5	2.2

* Winning Bid.

Source: Potential Future Role of Oil Shale: Prospects and Constraints, op. cit., appendix tables B-1 and B-2, aAppendix pp. 17, 18.

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unleased Wyoming tracts, are less suited to rapid commercial development using technologies on which there has been the most work. It is not unreasonable, therefore, to suppose that these premium tracts drew premium bids. Also, the first three prototype lease awards took place during the last three months of the Arab oil embargo, when there may have been expectations of continued oil shortages and/or rapidly rising world oil prices.

Taking into account both initial capital costs for production and bonus payments for the lease, it would appear then that something on the order of $1 billion in assets is required to undertake oil shale development.[39/] Because of their experience with both the processing technology and marketing channels, the major oil companies are the primary candidates among possible investors with a sufficiently large asset base, at least in the early stages. It is clear that the shale industry is not yet suited to small business and that, were it not for the oil companies, there would be much less interest in the industry's development.

Any evaluation of oil shale leasing policy must recognize one major fact: unlike offshore oil and gas, onshore oil and gas, and coal leasing, there is no past large-scale production experience from which inferences can be drawn about past leasing performance. Indeed, the commercial feasibility of any oil shale technology is yet to be proven. While one can speculate about the future impact of current leasing

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39/ Walter Mead gives one such estimate in Natural Resources Journal, 8 (October, 1968), pp. 604-631.

policies, there can be no definite answers until large-scale oil shale technology has been proven.

It can be seen in Table 6.1 that all of the winning bids on the prototype lease tracts and a number of the losing bids involved joint ventures including major oil companies. Some of the losing individual company bids were by large firms such as the Sun Oil Co., Exxon (Carter Oil Co.), and Shell Oil Co. Some were by smaller firms such as Occidental Oil Shale, Inc. Since individual major firms evidently considered themselves capable of entry into joint ventures, and given the tendency of joint ventures to reduce the number of independent sources of initiative, one might argue that joint oil shale development ventures among majors should be banned.

An alternative view is that because of the high risks involved, joint ventures should not be discouraged. If they increase the number of possible participants, as in the demonstration project, they may even be positively desirable. That joint ventures involving large companies bid higher in the 1974 lease sale could be attributable to greater risk spreading capability.

Both leasing experience and development experience on Federal oil shale lands have been too brief to warrant any judgment at this early date as to the effects of joint bidding on leasing competition. To be sure, the risk involved in a shale oil venture is high and might therefore appear to justify allowing joint bidding to make entry into competition more attractive. But the risk seems to be more at the development

stage of the venture--like some of the more advanced coal conversion proposals--than at the discovery stage--like OCS oil. There is the possibility, then, that means other than joint bidding can be found which will enable bidders to share these risks with other firms. Since new leasing in any quantity is, in any event, to be postponed until more developmental experience is gained on the four tracts already leased, we believe it is appropriate to defer any joint bidding restriction as well.

We recommend, then, that the decision on whether to restrict joint bidding for Federal oil shale lands be postponed to that time--possibly several years hence--when sufficient evidence on development and production experience shall have accumulated to warrant the resumption of leasing. At that time it will be more nearly feasible to assess the incidence of risk on the winner of an oil shale lease.

APPENDIX A

§ 3302.3-2 Joint bidding requirements

(a) Any person who submits a joint bid for any oil and gas lease during a six month bidding period must have filed under oath with the Director a Statement of Production of crude oil, natural gas, and liquefied petroleum products hereinafter referred to as a Statement of Production, no later than 45 days prior to the commencement of the applicable six month bidding period, except that for the initial bidding period commencing November 1, 1975, all Statements of Production must be filed no later than October 20, 1975. Statements of Production should be filed with the Director, Bureau of Land Management (attention: 722), Washington, D.C. 20240. A Statement of Production shall state whether or not the person filing the Statement of Production was chargeable in accordance with § 3302.3-3 with an average daily production in excess of 1.6 million barrels of crude oil, natural gas, and liquefied petroleum products for the prior production period. The Director will, no less than semi-annually, publish in the Federal Register a "List of Restricted Joint Bidders," to be effective immediately upon publication and to continue in force and effect until a subsequent list is published. The List of Restricted Joint Bidders shall be made up of those persons who in the judgement of the Director, based on information available to him, including, but not limited to, sworn Statements of Production, are chargeable under § 3302.3-3 with an average daily production in excess of 1.6 million barrels of crude oil, natural gas, and liquefied petroleum products for the prior production period.

(b) When a person is placed on the List of Restricted Joint Bidders the Director shall serve that person either personally or by certified mail, return receipt requested, with a copy of the Director's Order placing that person on the List of Restricted Joint Bidders. Any appeal from that Order or from an adverse effect of that Order shall be made in accordance with the provisions of 43 CFR Part 4.

(c) The submission of a Statement of Production or of a detailed Report of

duction under § 3302.4(d) which misrepresents the chargeable production of the reporting person shall constitute failure to comply with these regulations and any lease awarded in reliance on such Statement or Report of Production may be canceled, pursuant to section 8(i) of the Act and regulations issued thereunder as having been obtained by fraud or misrepresentation.

[40 FR 45172, Oct. 1, 1975]

§ 3302.3–3 Chargeability for production.

(a) As used in this section the following definitions shall control:

(1) *"Person"* means a natural person or company,

(2) *"Company"* means a corporation, a partnership, an association, a joint-stock company, a trust, a fund, or any group of persons whether incorporated or not; it also means any receiver, trustee in bankruptcy, or similar official acting for such a company.

(3) *"Subsidiary"* means a company 50 percent or more of whose stock or other interest having power to vote for the election of directors, trustees, or other similar controlling body of the company is directly or indirectly owned, controlled, or held with the power to vote by another company; a subsidiary shall be deemed a subsidiary of the other company owning, controlling, or holding 50 percent or more of the stock or other voting interest.

(4) *"Security or securities"* means any note, stock, treasury stock, bond, debenture, evidence of indebtedness, certificate of interest or participation in any profit-sharing agreement, collateral-trust certificate, pre-organization certificate or subscription, transferable share, investment contract, voting-trust certificate, certificate of deposit for a security, fractional undivided interest in oil, gas, or other mineral rights, or, in general, any interest or instrument commonly known as a "security" or any certificate of interest or participation in, temporary or interim certificate for, receipt for, guarantee of, or warrant or right to subscribe to or purchase any of the foregoing.

(b) A person filing a Statement of Production under § 3302.3–2 shall be charged with the following production during the applicable prior production period:

(1) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products which it owned worldwide;

(2) The average daily production in barrels of crude oil, natural gas, and liquefield petroleum products owned worldwide by every subsidiary of the reporting person;

(3) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any person or persons of which the reporting person is a subsidiary; and

(4) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any subsidiary, other than the reporting person, of any person or persons of which the reporting person is a subsidiary.

(c) A person filing a Statement of Production shall be charged with, in addition to the production chargeable under paragraph (b) of this section, but not in duplication thereof, its proportionate share of the average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every person: (1) Which has an interest in the reporting person, and (2) in which the reporting person has an interest, whether the interest referred to in paragraphs (c) (1) and (2) of this section is by virtue of ownership of securities or other evidence of ownership, or by participation in any contract, agreement, or understanding respecting the control of any person or of any person's production of crude oil, natural gas, or liquefied petroleum products, equal to said interest. As used in paragraph (c) of this section "interest" means an interest of at least 5 percent of the ownership or control of a person.

(d) All measurements of crude oil and liquefied petroleum products under this section shall be at 60° F.

(e)(1) For purposes of computing production of natural gas under § 3302.3–2, chargeability under this section, and reporting under § 3302.4(d), 5,626 cubic feet of natural gas at 14.73 pounds per square inch (msl) shall equal one barrel.

(2) For purposes of computing production of liquefied petroleum products under § 3302.3–2, chargeability under this section, and reporting under § 3302.4(d),

1.454 barrels of natural gas liquids at 60° F shall equal one barrel of crude oil.

[40 FR 45172, Oct. 1, 1975]

§ 3302.3–4 Bids disqualified.

The following bids for any oil and gas lease will be disqualified and rejected in their entirety:

(a) A joint bid submitted by two or more persons who are on the effective List of Restricted Joint Bidders; or

(b) A joint bid submitted by two or more persons when one or more of those persons has not filed the required Statement of Production pursuant to § 3302.3–2 for the applicable six month bidding period, or when one or more of these persons has failed or refused to file a detailed Report of Production when required to do so under § 3302.4(d); or

(c) A single or joint bid submitted pursuant to an agreement (whether written or oral, formal or informal, entered into or arranged prior to or simultaneously with the submission of such single or joint bid, or prior to or simultaneously with the award of the bid upon the tract) which provides (1) for the assignment, transfer, sale, or other conveyance of less than a 100 percent interest in the entire tract on which the bid is submitted, by a person or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or (2) for the assignment, sale, transfer or other conveyance of less than a 100 percent interest in any fractional interest in the entire tract (which fractional interest was originally acquired by the person making the assignment, sale, transfer or other conveyance, under the provisions of the Act) by a person or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or (3) for the assignment, sale, transfer, or other conveyance of any interest in a tract by a person or persons not on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to two or more persons on the same List of Restricted Joint Bidders; or (4) for any of the types of conveyance described above in Paragraph (c) (1), (2), or (3) where any party to the conveyance has not filed a Statement of Production pursuant to § 3302.3–2 for the applicable six month bidding period. Assignments expressly required by law, regulation, lease, or stipulation to lease shall not disqualify an otherwise qualified bid; or

(d) A bid submitted by or in conjunction with a person who has filed a false, fraudulent or otherwise intentionally false or misleading Statement of Production or detailed Report of Production.

[40 FR 45173, Oct. 1, 1975]

§ 3302.4 What must accompany bids.

(a) A separate bid must be submitted for each lease unit described in the notice of lease offer. A bid may not be submitted for less than an entire unit. Each bidder must submit with his bid a certified or cashier's check or bank draft on a solvent bank, or a money order or cash, for one-fifth of the amount of the cash bonus. If the bidder is an individual, he must submit with his bid a statement of his citizenship. If the bidder is an association (including a partnership), the bid shall be accompanied also by a certified copy of the articles of association or appropriate reference to the record of the Bureau of Land Management in which such a copy has already been filed, with a statement as to any subsequent amendments. If the bidder is a corporation, the following additional information shall be submitted with the bid.

(1) A certified copy of the articles of incorporation and a copy either of the minutes of the meeting of the board of directors or of the by-laws indicating that the person signing the bid has authority to do so, or, in lieu of such a copy, a certificate by the secretary or the assistant secretary of the corporation to that effect, over the corporate seal or appropriate reference to the record of the Bureau of Land Management in connection with which such articles and authority have been previously furnished.

(b) All bidders are warned against violation of the provisions of Title 18 U.S.C. section 1860, prohibiting unlawful combination or intimidation of bidders

(c) In addition to the above, every joint bid submitted for any oil and gas lease shall be accompanied by a sworn statement by each joint bidder stating that the bid is not disqualified under § 3302.3–4(c).

(d) To verify the accuracy of any statement submitted pursuant to §§ 3302.3–2 and paragraph (c) of this section the Director may require the person submitting such information to (1) submit no later than 30 days after receipt of request by the Director a detailed Report of Production which shall list in barrels the average daily production of crude oil, natural gas, and liquefied petroleum products chargeable to the reporting person in accordance with § 3302.3–3 for the prior production period, and (2) permit the inspection and copying by an official of the Department of the Interior of such documents, records of production of crude oil, natural gas, and liquefied petroleum products, analyses and other material as are necessary to demonstrate the accuracy of any statement or information upon which any information in any Statement of Production or Report of Production was based or from which it was derived.

[35 FR 9695, June 13, 1970, as amended at 40 FR 45172, Oct. 1, 1975]

§ 3302.5 Award of lease.

Sealed bids received in response to the Notice of Lease Offer shall be opened at the place, date and hour specified in the notice. The opening of bids is for the sole purpose of publicly announcing and recording the bids received and no bids will be accepted or rejected at that time. In accordance with section 8 of the Act, leases will be awarded only to the highest qualified responsible bidder. The United States reserves the right and discretion to reject any and all bids received for any tract, regardless of the amount offered. Awards of leases will be made only by written notice from the authorized officer. Such notices shall transmit the lease forms for execution. In the event the highest bids are tie bids, the bidders, unless they would be disqualified under § 3300.1, or disqualified under § 3302.3–4 if their bids had been a joint bid, may file with the Director, within 15 days after notification, an agreement to accept the lease jointly; otherwise all bids will be rejected. If the authorized officer fails to accept the highest bid for a lease within 30 days after the date on which the bids are opened, all bids for that lease will be considered rejected. Notice of his action will be transmitted promptly to the several bidders. If the lease is awarded, three copies of the lease will be sent to the successful bidder and he will be required not later than the 15th day after his receipt thereof, or the 30th day after the date of the sale, whichever is later, to execute them, pay the first year's rental and the balance of the bonus bid, and file a bond as required in § 3304.1. Deposits on rejected bids will be returned. If the successful bidder fails to execute the lease within the prescribed time or otherwise comply with the applicable regulations his deposit will be forfeited and disposed of as other receipts under the Act. If before the lease is executed on behalf of the United States the land which would be subject to the lease is withdrawn or restricted from leasing, the bidder will lose all right to the lease and all payments made by the bidder will be refunded to him. If the awarded lease is executed by an agent acting in behalf of the bidder, the lease must be accompanied by evidence that the bidder authorized the agent to execute the lease. When the three copies of the lease are executed by the successful bidder and returned to the authorized officer, the lease will be executed on behalf of the United States, and one fully executed copy will be mailed to the successful bidder.

[40 FR 45173, Oct. 1, 1975]

APPENDIX B

APPENDIX B

PROHIBITION OF CERTAIN LEASE BIDDING ARRANGEMENTS

Sec. 105.(a) The Secretary of the Interior shall, not later than 30 days after the date of enactment of this Act, prescribe and make effective a rule which prohibits the bidding for any right to develop crude oil, natural gas, and natural gas liquids on any lands located on the Outer Continental Shelf by any person if more than one major oil company, more than one affiliate of a major oil company, or a major oil company and any affiliate of a major oil company, has or have a significant ownership interest in such person. Such rule shall define affilitate relationships and significant ownership interests.

(b) As used in this section:

(1) The term "major oil company" means any person who, individually or together with any other person with respect to which such person has an affiliate relationship or significant ownership interest, produced during a prior 6-month period specified by the Secretary, an average daily volume of 1,600,000 barrels of crude oil, natural gas liquids equivalents, and natural gas equivalents.

(2) One barrel of natural gas equivalent equals 5,262 cubic feet of natural gas measured at 14.73 pounds per square inch (MSL) and 60 degrees Fahrenheit.

(3) One barrel of natural gas liquids equivalent equals 1.454 barrels of natural gas liquids at 60 degrees Fahrenheit.

(c) The Secretary may, by amendment to the rule, exempt bidding for leases for lands located in frontier or other areas determined by the Secretary to be extremely high risk lands or to present unusually high cost exploration, or development, problems.

(d) This section shall not be construed to prohibit the unitization of producing fields to increase production or maximize ultimate recovery of oil or natural gas, or both.

(e) The Secretary shall study and report to the Congress, not later than 6 months after the date of enactment of this Act, with respect to the feasibility and desirability of extending the prohibition on joint bidding to --

(1) bidding for any right to develop crude oil, natural gas, and natural gas liquids on Federal lands other than those located on the Outer Continental Shelf; and

(2) bidding for any right to develop coal and oil shale on such lands.